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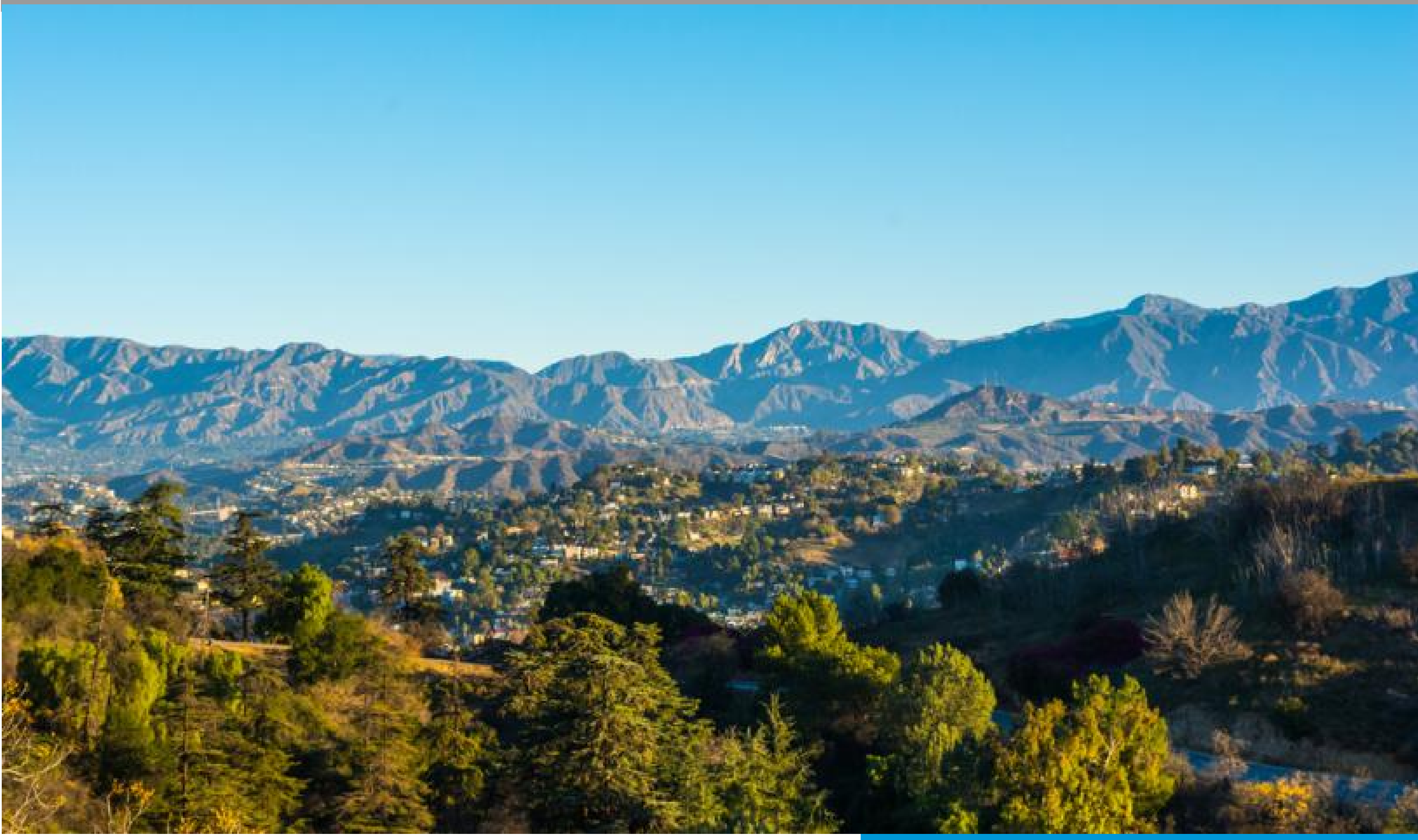
DRAFT PROPOSAL

Demand Response QC Preliminary Proposal



Prepared by:

Demand Side Analytics

Pacific Gas and Electric

Sand Diego Gas & Electric

Southern California Edison

California Large Energy Consumers Association

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1 INTRODUCTION

This preliminary report is prepared for consideration by members of the CEC working group on the QC (QC) of demand response (DR) resources. Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, Demand Side Analytics, and the California Large Energy Consumers Association convened to formulate workable solutions, based on some common principles. The group is still discussing and working out the details to find common ground. The proposal is preliminary and not final, and each organization will determine whether to support the proposal after additional discussions. Due to complexity of the topic, we requested a revised deadline to submit draft proposals, but have yet to receive a response with a decision.

There are two proposals for consideration: (1) Loss of Load Probability weighted DR load impacts with minimum operational requirements and (2) Net Load Proxy Effective Load Carrying Capacity (ELCC). The LOLP weighted load impacts is simpler to implement but has limitations. The Net Load ELCC proxy better incorporates how DR interacts with resources such as solar, wind, and battery storage, includes more granular modeling of DR limitations, and produces outputs to inform how each operating characteristic affects the contribution of DR towards reliability.

One of the criteria of the permanent methodology is compatibility with the slice-of-day framework, which the CPUC will adopt in an upcoming Resource Adequacy (RA) decision (expected in June). At this time, we are still missing some critical information on future RA program design. We highly recommend deciding on a proposed framework after the RA decision is adopted.

The proposal we are submitting has a few overarching goals:

- Incorporate DR characteristics and use limitations into QC determination in a simple, transparent, and open-source manner;
- Ensure the framework accounts for the characteristics of each resource;
- Account for interactive effects of the supply mix;
- Produce estimates of DR capability that align with system peak days and slice of day RA framework;
- Enable year-ahead RA planning and long-term planning; and
- Ensure accurate measurement of the demand reductions delivered and the resource capabilities when the electric grid is at risk of resource shortages.

Demand response resources include a wide range of technologies and customer segments. They can vary in shape, weather sensitivity, and operating limitations such as the maximum event duration, number of consecutive dispatch days, and annual hours of dispatch. As such, QC (QC) valuation for DR is a complex topic. However, the issues raised as part of the working group can be classified into four main questions:

1) What is the DR capability under the RA planning conditions?
2) How are the characteristics of DR accounted for in determining the QC value? Specifically, how does the approach account for the coincidence of DR with resource needs and for its limitations on availability, event duration, and frequency of dispatch?
3) How do we improve the annual process and schedule for Resource Adequacy QC?
4) How do we measure DR performance?

The proposal focuses on the first two questions due in part to the limited time to produce a draft proposal on this complex topic. While we are open to improving the annual RA process for QC determination, changing the RAQC timeline and process affects resources other than DR, and should be done with caution. We are also open to improving and simplifying the Load Impact Protocols – the document that outlines evaluation requirements. However, due to its technical nature, we recommend avoiding major changes to them as part of this effort and limiting any changes to modifying outputs so they can be used for RAQC.

The remainder of the proposal is divided into three main sections. Section 2 presents the California context and motivation. Section 3 presents the LOLP weighted load impacts proposal. Section 4 presents the Net Loads ELCC proxy proposal. For each of the proposals, we describe the main concept, outline the calculation steps, provide an applied example, discuss it's alignment with the working group principles, and discuss how of the proposal aligns with the proposed slice of day RA frameworks. Finally, we conclude by discussing the limitations of other approaches.

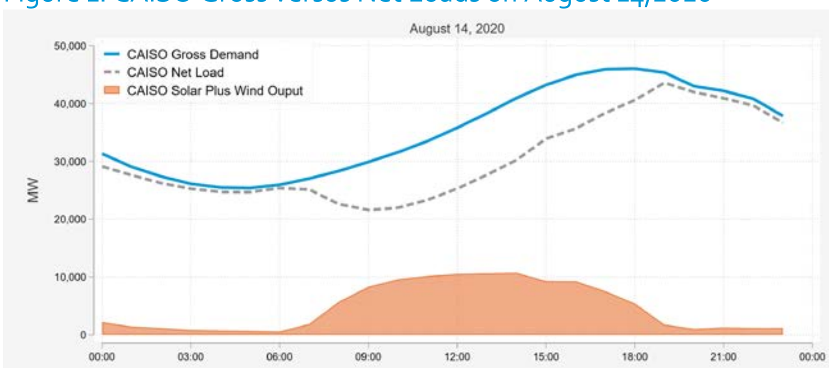
2 CALIFORNIA CONTEXT AND MOTIVATION

The fundamental nature of how electricity is generated, transmitted, distributed, and used in California changed substantially in the past ten years and will continue to evolve in the next decade. The single largest change affecting California's electric grid is de-carbonization goals. The penetration o of intermittent, utility-scale renewable generation, mostly in the form of large solar power facilities and wind farms, has grown substantially in the past decade. In 2021, solar resources delivered up to 13,000 MW and wind resources exceed 6,000 MW.[1] In addition, residential households and businesses are also installing behind-the-meter solar, installing battery storage, and increasingly adopting electric vehicles.

Historically, the electric grid infrastructure has been sized to meet the aggregate peak demand of end users plus a reserve margin for extreme weather or unforeseen outages. The electric system is unique in that it is necessary to balance supply and demand at all times. An imbalance can lead to cascading outages, and compromise the reliability of the entire grid. Because electricity storage used to be prohibitively expensive, historically, enough supply capacity and flexibility had to be built to accommodate peak demands and enough reserves had to be maintained to withstand un-forecasted changes in the supply-demand balance (e.g., generator outages). However, the technology for energy storage has evolved, and the costs are declining. California's generation interconnection queue includes a large amount of battery storage.

The introduction of large-scale amounts of solar and wind has led to fundamental changes in planning the electric grid. The focus has shifted from planning for peak demand to net loads – electricity demand minus large-scale solar and wind. The focus is on having sufficient dispatchable resources to meet the demand that cannot be met using solar and wind resources. Figure 1 illustrates the concept of net loads versus gross demand. It shows the electric demand and the wind and solar production on August 14, 2020, a day when California had experienced a shortage in resources. While demand peaks in the late afternoon, net loads peak a couple of hours later, when solar production declines as the sun sets. The ongoing changes lead to a cleaner supply mix, but also affect the magnitude and type of resources and grid services required to maintain reliability.

Figure 1: CAISO Gross versus Net Loads on August 14,2020

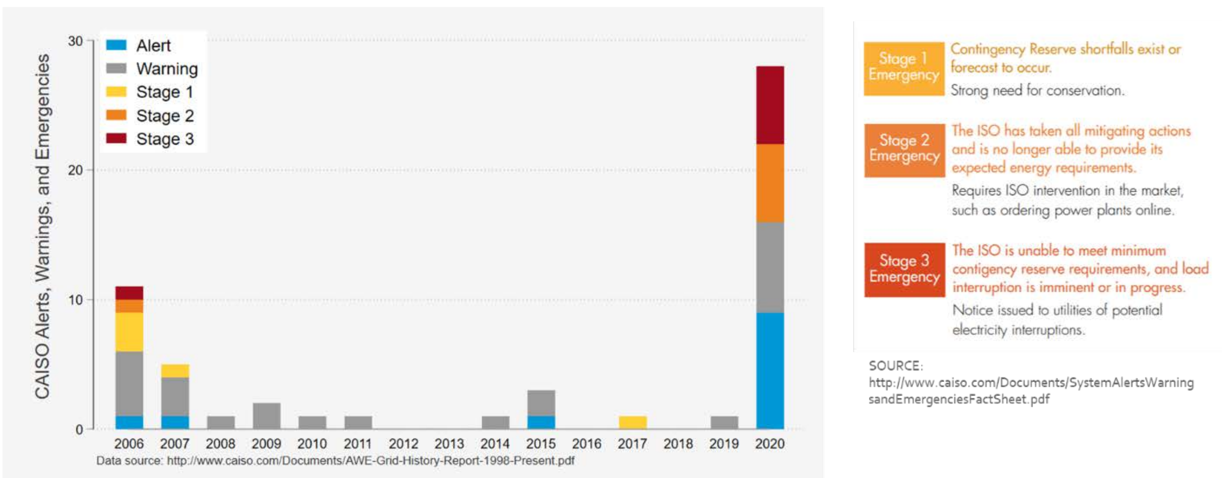


[1] CAISO press release. http://www.caiso.com/Documents/California-ISO-Hits-All-Time-Peak-of-More-Than-97-Percent-Renewables.pdf

They place a premium on flexible resources: enough flexibility is needed so supply can be adjusted to meet fluctuations in demand and fill gaps when solar and wind power are not available.

In 2020, California experienced a confluence of hotter weather and fires, leading to a historic number of CAISO emergency events, including rolling blackouts. The emergencies occurred due to a mix of high demand, unusual conditions, lower than forecasted solar output, operator forecasting error, and planning paradigms that focused on gross demand rather than net loads. Demand response played a critical role in helping reduce demand when resources were needed. In 2020, the resources shortages did not occur when peak demand was at its highest but later in the evening when net loads (demand minus solar and wind) peaked.

Figure 2: Historical CAISO Alerts, Warnings, and Emergencies



2.1 DEMAND RESPONSE RESOURCES AND CAISO PEAKING PATTERNS

Historically, demand response programs have been designed to reduce peak demand and offset the need for additional peaking capacity. When, where, how often, and for how long DR resources are needed are evolving due to the introduction of large amounts of intermittent renewable resources.

A fundamental characteristic of power system planning is that a small number of hours drive a significant share of costs. When the grid is strained, either due to high demand, generator outages, transmission outages, fluctuations in power output, or forecast error, electricity prices climb sharply. Resource shortages typically occur due to high demand levels and a combination of generator outages, transmission outages, low imports, or un-forecasted fluctuations in solar or wind output.

Figure 3 shows the concentration of CAISO high net load days and hours and days. The panel to the left is a load duration curve, which ranks the top 5% of hours based on net loads from highest to lowest. The panel to the right shows the hourly patterns on the ten days with the highest CAISO net loads. Net loads are the primary driver of resource capacity needs and are highly concentrated. The net loads in roughly 1% of the hours in the year drive the need for 18% of the resources (over 9,000 MW with the reserve margin). Moreover, the timing of the high net loads is concentrated in the summer months and on specific hours. Figure 4 shows a heat map of CAISO net loads in 2020. Even in unusual years, such as 2020, the risk of resource shortages is concentrated in a limited number of hours in summer months and driven by heatwaves.

Figure 3: CAISO Concentration of High Net Load Hours and Days

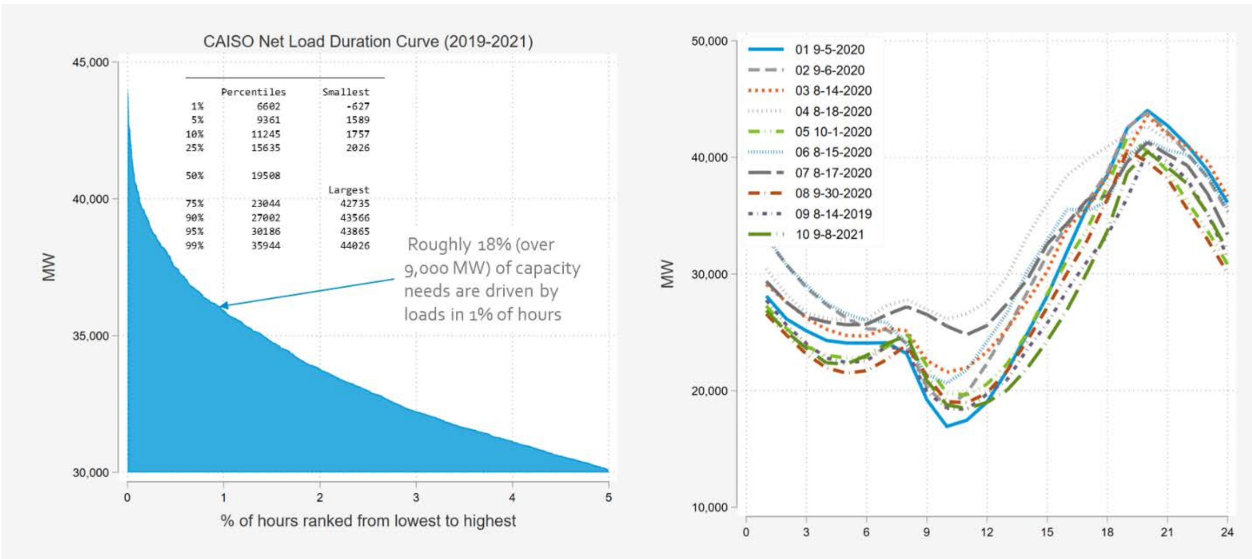
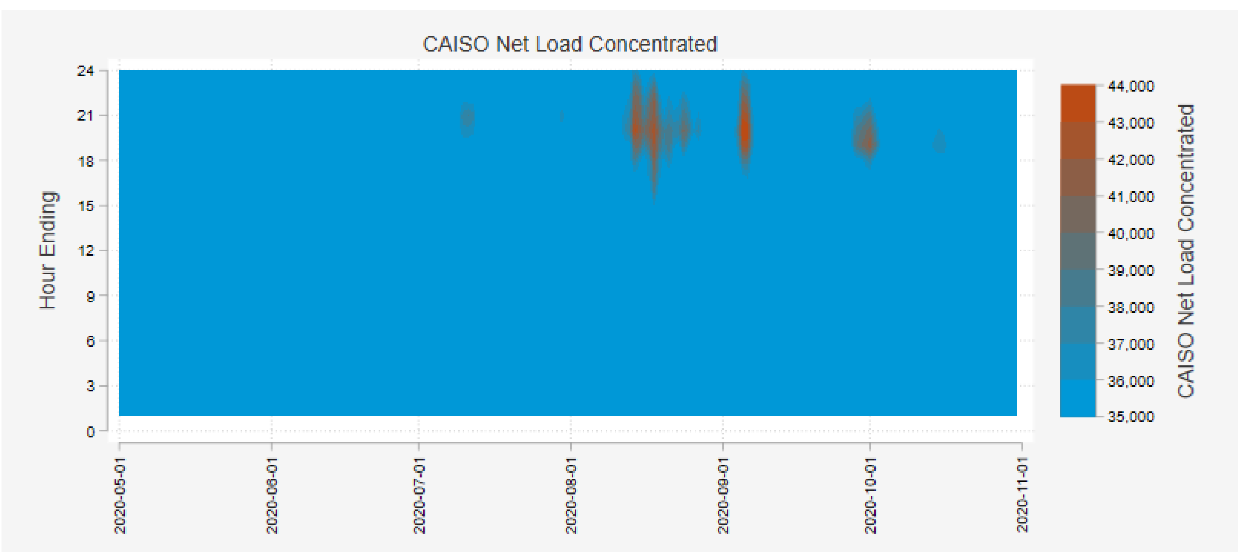
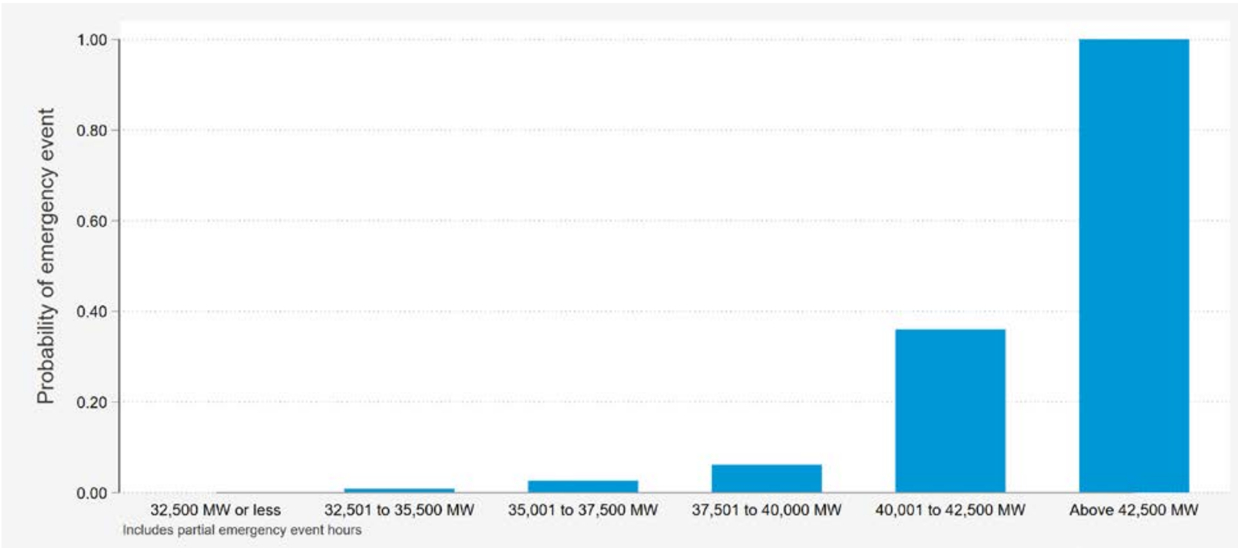


Figure 4: Heat Map of CAISO Net Load in Summer 2020



High net loads are closely related to resource shortages as measured by CAISO emergency notices, which are directly linked to the available reserve margin. Figure 5 shows the relationship. The probability of resource shortages in 2019-2021 was directly linked to net loads. The risk of resource shortages was highest when loads exceeded 40,000 MW.

Figure 5: 2019-2021 Relationship Between Net Loads and CAISO Emergency Events



To help meet resource adequacy requirements, DR resources need to be available and delivered in the right months and right hours when net loads are high. Because net loads drive planning needs, the framework of DR QC must account for the level of solar and wind penetration. DR includes a wide range of resources ranging from residential thermostats, behind-the-meter batteries, to large industrial customers, each with differing capabilities on when, how often, how long, and how much demand reduction they can deliver. It is our position that any QC framework must properly incorporate and model the use limitations of DR resources and their coincidence with resource needs. DR resources also interact with battery storage. Both resources effectively aim to shave the net load duration curve, targeting the hours when resources are needed most. Higher amounts of peak shaving resources effectively mean that the resources must be dispatched more often to shave the load duration curve.

The main takeaways are simple:

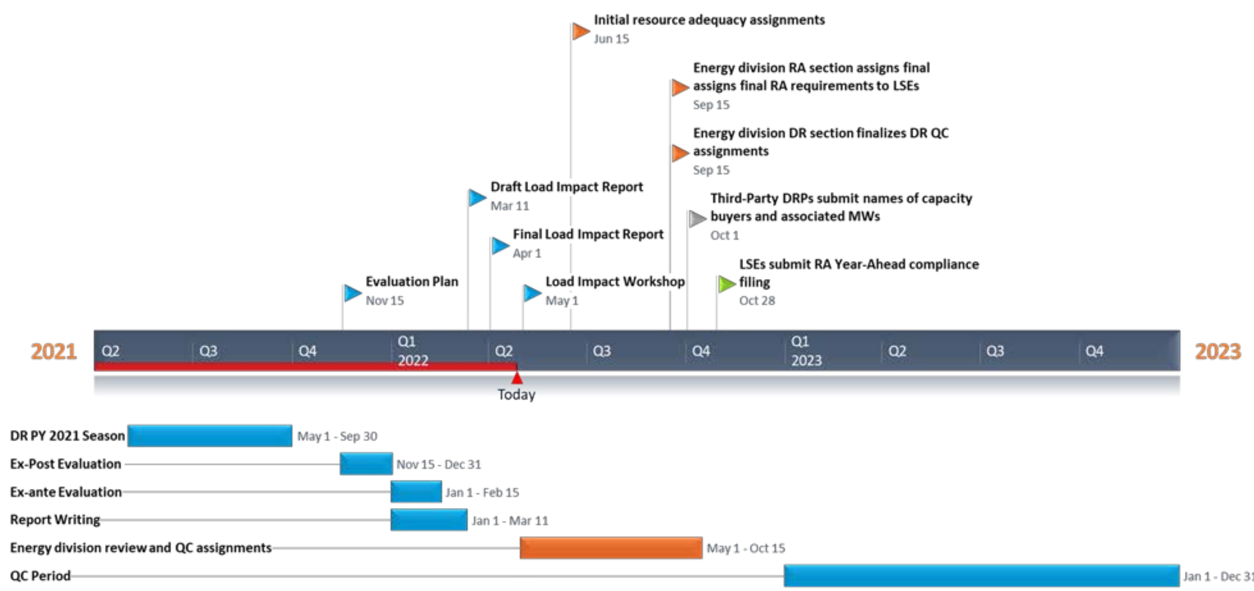
- Planning has shifted from gross loads to net loads. Wind and solar are effectively the base supply resource but are inherently intermittent.
- Electricity infrastructure costs are currently driven by net loads which are highly concentrated, peaking on a limited number of hours and days. Over 9,000 MW of capacity resources (18%) are needed due to high net loads in less than 1% of hours.
- Empirically, high net loads are closely linked to resource shortages. The likelihood of shortages increases as net loads grow.

- To deliver resource adequacy, DR resources need to be available and deliver resources in the months and hours when net loads are high. Because net loads drive planning needs, the DR QC framework must account for the level of solar and wind penetration.
- DR also interacts with battery storage, since both resources have use limitations; target the hours when resources are needed most; and aim to shave the net load duration curve.

2.2 CURRENT DEMAND RESPONSE QUALIFYING CAPACITY

Figure 6 below shows the current timeline for Demand Response QC. The load reduction capabilities are based on actual performance over multiple years. The ex-post evaluations estimate the magnitude of load reductions actually delivered, based on the number of customers dispatched, hours of dispatch, and conditions at the time. The evaluations produce and track results in a standard format, and provide a multi-year history of demand response performance. Currently, most evaluations rely on smart meter data, and are implemented either using matched control groups and differences-in-differences panel regressions or individual customer regressions. The evaluations have validation requirements, and typically include a tournament with out-of-sample testing to identify the best performing model. The ex-ante impacts are designed to inform the load reduction capability under a standard set of conditions. They produce hourly load impact, by month, for extreme (1-in-10) and normal (1-in-2) CAISO and utility monthly peaking conditions and, when possible, are grounded on historical performance (i.e., ex-post). Once the evaluation is complete, the California Public Utilities Commission (CPUC) Energy Division reviews the evaluation report, and begins the process of assigning QC values.

Figure 6: Illustrative DR QC timeline



The current process presents several challenges:

- **The QC values do not account for hourly patterns of DR. The current approach produces a single value per month, which is the simple average hourly load impacts from 4-9 PM.** It does not reflect the hourly load reduction capability, even though the information is provided as an output of the load impact evaluations. It also does not reflect the flexibility of some resources (e.g., the ability to dispatch them between 12 PM and 11 PM) or the ability to deliver reductions for longer than five hours.
- **The QC values do not fully account for the characteristics and use limitations of DR.** For example, the approach does not account well for weather-sensitive programs that can deliver larger reductions when it is hotter and resources are needed most. It also does not fully account for the use limitations of DR such as limits on max event duration, consecutive event days, and annual number of event hours. The limitations are accounted for indirectly via minimum requirements. Currently, to be counted for RA QC, a DR program must be available Monday – Saturday, four consecutive hours between 4 PM and 9 PM, and at least 24 hours per month from May – September, as shown in the table below from the most recent Commission decision establishing the maximum cumulative capacity buckets.[2]
- **Timeline lag.** The DR QC values for 2023 rely on the load impact evaluation for 2021, a nearly two-year lag. Moreover, the capability is based on enrollment forecasts that are not updated, as better information (i.e., weather) becomes available.

2.3 LOSS OF LOAD PROBABILITY MODELS AND EFFECTIVE LOAD CARRYING CAPACITY

The fundamental question is how to count DR's contribution to reliability, given the resource load shapes, coincidence with need, and use limitations. The concept of effective load carrying capacity (ELCC) is to estimate the contribution of a resource to reliability, given its operating characteristics. For example, thermal generators require fuel supply, and can fail at higher rates when temperatures get hotter (forced outages); hydro power plants are subject to drought years; solar produces energy when the sun shines; wind produces energy when the wind blows; and battery storage has a limited storage capacity that needs to recharge.

By definition, DR resources either reduce demand or shift electricity use. - They do not produce power. They are best suited to deliver capacity on a limited number of days and hours or to supply ancillary services such as operating reserves. However, they are in the supply stack, and submit bids to CAISO, in order to provide visibility into the resources available and to qualify for capacity. One of the key challenges with DR is the temptation to over-utilize DR resources. Many, but not all DR resources, can be dispatched quickly, and have low start-up costs. However, customers experience costs the more

[2] D21-06-029

frequently and the longer that they are dispatched. A home can maintain a reasonable indoor temperature with reduced AC use for several hours, but, at some point, the inherent thermal storage from insulation is used up, and indoor temperatures rise. Likewise, an industrial customer may be able to shift or reduce demand on a handful of days, but frequent curtailments can become disruptive to their core business. Thus, a balance needs to be struck between providing load relief when resources are needed most and overuse of DR resources.

CAISO has advocated the use of LOLP models to estimate the ELCC because it accounts for interactive effects with other resources such as wind, solar, and battery storage and because it can account for the use limitations of DR. The ELCC approach has some severe limitations:

- **Complexity:** The LOLP model ELCC approach uses a probabilistic resource planning model, which simulates dispatch over hundreds of simulated years. Most simulated years and hours do not show resource shortages, and the loss of load probability is highly concentrated on a limited number of simulation runs on a limited number of hours. The approach relies on many assumptions and extensive inputs. There are assumptions to construct resource profiles for different weather years, assumptions about the distribution of uncertainty of different types of resources, assumptions about whether the uncertainty is normally distributed or not, assumptions about the operating characteristics of each resource, and assumptions about the future supply mix.
- **Lack of transparency and cost**. The software used is not always public and it is costly. For example, E3 model is confidential and proprietary. The public software typically costs over a $100k to access, and requires extensive expertise and training to operate. Moreover, the input assumptions are not all public. When they are, they not detailed with sufficient specificity. DR providers cannot be expected to replicate the analysis to understand if and why a resource received the QC value assigned to it. The lack of transparency breeds a lack of confidence regarding how DR use limitations are incorporated into the modeling.
- **Inconsistency**. LOLP models are designed to estimate the portfolio ELCC, which includes the entire supply mix. They are not designed to produce ELCC values for individual resources. In fact, they produce inconsistent results when applied to individual resources. The sum of the individual resources does not add up to the Portfolio ELCC. They are also prone to the method used. The first-in and last-in approaches produce different values. Despite all the modeling complexity, the inconsistency of the ELCC assigned to individual resource (and resource types) is dealt with in a simplistic manner – the results for the individual resources are scaled, after-the-fact to match the portfolio ELCC.
- **Impracticality with QC Timeline.** The time, effort, expertise, and complexity of running LOLP models to estimate ELCC make it impractical to introduce this step into a QC timeline that is already overly complex and overly long.

While we support the fact that DR use limitations need to be accounted for in resource planning, our goal is to develop a simpler, more transparent, less expensive, faster, and more reasonable approach.

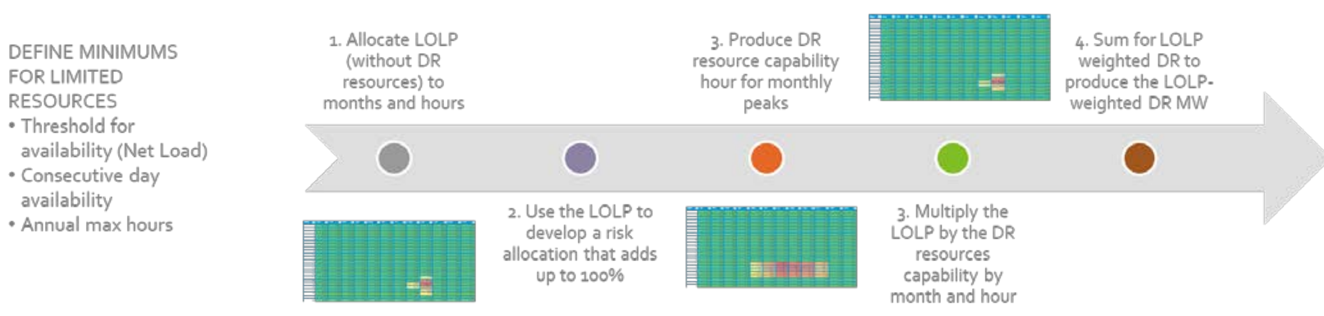
3 LOLP WEIGHTED LOAD IMPACTS PROPOSAL

The fundamental concept of the proposal is to produce and use LOLP heat maps by month and hour and use them to calculate LOLP weighted impacts. The approach makes use of the fact that the Load Impact Protocols and the proposed slice-of-day resource adequacy (RA) framework focus on the hourly resource capability during monthly system peak conditions. They also reflect the reality that the focus is on resource adequacy for the upcoming summer, and the supply mix is relatively well defined over the horizon.

A common practice for assessing resource adequacy is to employ loss of load probability (LOLP) models. These models are probabilistic and simulate both demand and supply for many years. They attempt to reflect the fact that weather patterns can vary and the exact amount of supply is uncertain due to generator outages, hydro conditions, the amount of imports available, and solar and wind output. They effectively simulate both demand and supply thousands of times using different weather years to identify when resource shortages are likely to occur and the effect of changing the supply mix on the likelihood of resource shortages.

The models are typically used to assess the LOLP in future years. These models underlie the ELCC calculations, which attempt to measure how much resource(s) contribute toward reliability. The LOLP models produce very granular details about the conditions that led to resource outages for each simulation run, including when they occurred, how often, and magnitude of the resource shortage. A common practice is to produce LOLP heat maps by month and hour, which help DR resources understand which hours to target and adjust program rules accordingly. The heat maps can be produced at more granular levels – by month, hour, and weekday/weekend – and can also show the depth of the simulated shortages (the Expected Unserved Energy) rather than binary probabilities.

The figure below illustrates the main concept.



There are few important nuances:

- The LOLP values are produced *in advance* but model the resource adequacy year(s) in question. Having the LOLP table available ahead of time allows DR providers to better target the right hours, and it also avoids additional delays in the QC process due to additional modeling.

- We recommend the LOLP heatmap be based on modeling that removes DR resources, so they better reflect the hours and months when DR resources are needed most.
- DR providers will need to complete a table specifying the magnitude and availability of their DR resource(s) by month and hour. The table should incorporate any maximum event duration limitations for the resource. The resource capability should be based on ex-post evaluation of performance over the three most recent years.
- DR providers with less than 10 MW and less than three years of operations in the California market are exempt from paying for load impact evaluations. The DRMEC will commission a study to independently evaluate new entry resources and estimate realization rates. Total resources exempted cannot exceed 10% of the total California DR portfolio.
- A set of minimum requirements needs to be established for other factors that limit use of DR. Any requirements need to reasonable and to avoid being overly broad. They also will need to be updated as additional solar, wind, and battery storage come online. In specific, we recommend:
  - ✓ A threshold for availability, ideally based on net loads. For example, DR resources must be available whenever net loads exceed 38,000 MW.
  - ✓ Availability for a minimum number of event days. For example, 3 events days.
  - ✓ Availability for a minimum number of annual event hours. For example, 100 event hours.
- The LOLP outputs and minimum requirement would need to be updated every other year.
- The ex-ante load impact protocols should be updated for net load peaking conditions (versus gross demand), and updated to include the reduction capability for weekdays and weekends.

The above approach makes use of the existing DR load impact evaluation protocols, which require standardized reporting of performance during actual events (ex-post impacts), and require the standardized reporting of hourly demand reduction capability for standardized monthly system peak days conditions (ex-ante impacts). Moreover, the existing evaluation protocols require that, whenever possible, ex ante estimates of DR impacts should be informed by ex-post empirical evidence from existing or prior DR resource options.

3.1 CALCULATION STEPS AND APPLIED EXAMPLE

	Description	Example
1	Produce an LOLP table by month, hour, and weekday /weekend	See table below

LOLP 2023 (Produced in 2021-22)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	0.000098	-	-	-
18	-	-	-	-	-	-	-	-	0.001814	-	-	-
19	-	-	-	-	-	-	-	0.000190	0.002843	-	-	-
20	-	-	-	-	-	-	-	0.000047	0.001569	-	-	-
21	-	-	-	-	-	-	-	-	0.000539	-	-	-
22	-	-	-	-	-	-	-	-	0.000098	-	-	-
23	-	-	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-

TOTAL LOLP 0.007198

	Description	Example
2	Use the LOLP to develop a risk allocation - by month, hour, and weekdays/ weekend - that sums to 100%.	See table below

Relative LOLP - Adds up to 100%

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
8	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
9	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
11	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
17	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%	0.0%	0.0%	0.0%
18	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	25.2%	0.0%	0.0%	0.0%
19	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%	39.5%	0.0%	0.0%	0.0%
20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	21.8%	0.0%	0.0%	0.0%
21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.5%	0.0%	0.0%	0.0%
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%	0.0%	0.0%	0.0%
23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

TOTAL Relative LOLP 100%

	Description	Example
3	Produce load impact estimates by month, hour, and weekday/weekend. Load impacts are produced for the 1-in-10 monthly peak day. The user applies any resource event duration constraints, and defines the hours of availability	See table below

Hourly Load Impacts on Monthly Peak Day (MW)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	12.31	34.97	52.24	98.85	76.36	63.59	0.00	0.00
18	0.00	0.00	0.00	0.00	9.17	35.21	52.52	97.68	91.21	82.41	0.00	0.00
19	0.00	0.00	0.00	0.00	7.21	32.24	50.55	94.48	85.39	74.60	0.00	0.00
20	0.00	0.00	0.00	0.00	10.41	28.92	29.99	74.58	65.60	55.34	0.00	0.00
21	0.00	0.00	0.00	0.00	10.37	27.80	29.69	73.46	62.75	54.86	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

<table>
<tr><th></th><th>Description</th><th>Example</th></tr>
<tr><td>4</td><td>Multiply each cell in the table in Step 2 by the table in Step 3. The results are in interim calculation to get to the LOLP weighted load impacts</td><td>Interim Step for LOLP weighted load impact (Step 2 table x Step 3 table)
<table>
<tr><th>Hour</th><th>Jan</th><th>Feb</th><th>Mar</th><th>Apr</th><th>May</th><th>Jun</th><th>Jul</th><th>Aug</th><th>Sep</th><th>Oct</th><th>Nov</th><th>Dec</th></tr>
<tr><td>1</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
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<tr><td>5</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>6</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>7</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>8</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>9</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>10</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>11</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>12</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>13</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>14</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>15</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>16</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>17</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>1.04</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>18</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>22.98</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>19</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>2.49</td><td>33.73</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>20</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.49</td><td>14.29</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>21</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>4.70</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>22</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>23</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
<tr><td>24</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td><td>0.00</td></tr>
</table>
LOLP Weighted Load Impact 79.73</td></tr>
<tr><td>5</td><td>Sum up the values in the table from Step 4 to produce the LOLP weighted load impacts. In the example, the magnitude of the resource does not coincide perfectly with need.</td><td>LOLP weighted Load Impact = 79.73</td></tr>
</table>

3.2 ALIGNMENT WITH WORKING GROUP PRINCIPLES

	Principle	How the proposal meets the principle
1	Transparent and understandable	The approach does not rely on behind-the-scenes calculations and models that are unavailable to parties. The math required is the basic mathematical functions of multiplication and addition.
2	Based on the best available information regarding resource capabilities, including recent historical performance and participant enrollment and composition projections	The approach incorporates the most recent historical performance. It also provides DR providers the ability to update the values the reflect the most recent enrollments.
3	Allow DR providers to quickly determine or update QC values.	The DR providers can update the QC values quickly under the approach.
4	Consistent and compatible with the resource adequacy program a. Single-value RA program (status quo)	The approach is consistent with all three resource adequacy options. It can produce a single value, the load impact table by month and hour can be directly employed in the 24-hour slice of day proposal. Because

	b. Twenty-four-slice proposal (SCE) c. Two-slice proposal (Gridwell)	the approach relies on the LOLP models to produce the LOLP heat map, it is consistent with the two-slice approach. The only difference is that we request the project LOLP values as an input into the process.
5	Account for any use limitations, availability limitations, and variability in output of DR resources	The approach directly accounts for availability limitations by month hour, availability by net load peaking level, coincidence of DR with need, and limitations of consecutive event days, and annual event hours.
6	Translate a DR resource's load reduction capabilities into its reliability value.	The approach produces the DR reliability value by accounting for the coincidence of the resource with the risk of resource shortages. Resource availability during hours that coincide with the highest risk of shortages are weighted more heavily.
7	Include methods to determine delivered capacity (ex-post) that are compatible with the determination of QC (ex-ante)	The approach makes use of the existing DR load impact evaluation protocols, which require standardized reporting of performance during actual events (ex-post impacts) and require the standardized reporting of hourly demand reduction capability for standardized monthly system peak days conditions (ex-ante impacts). Moreover, the existing evaluation protocols require that, whenever possible, ex ante estimates of DR impacts should be informed by ex post empirical evidence from existing or prior DR resource options.
8	Not a substantial barrier to participation in the RA program.	The approach reduces and removes barriers to participation in the resource adequacy program
9	Account for a resource's capacity when reliability needs are highest	The approach accounts for capacity for monthly system peak days and the high net load periods when reliability needs are highest.

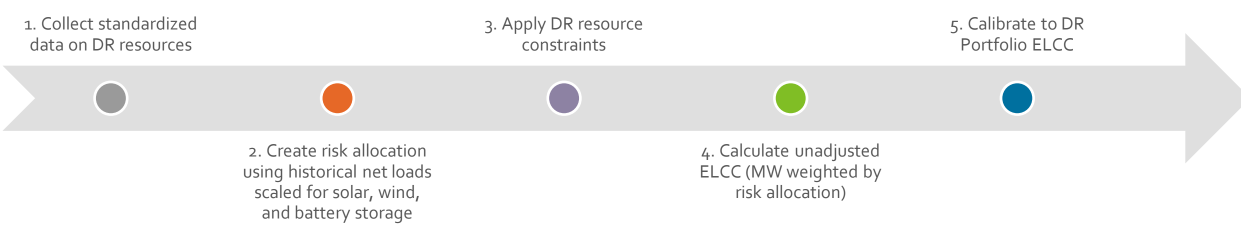
4 NET LOAD ELCC PROXY PROPOSAL

A distinctive feature of demand response is that it includes a wide range of technologies and customer types with diverse loads. From a resource adequacy standpoint, an ideal resource is available at all hours, predictable, able to quickly ramp resource (or reduction) levels up and down, and without limitations on when, for how long, and how often it can deliver capacity. Most types of DR and most types of generation deviate from the ideal resource.

The Net Load ELCC proxy proposal directly measures and models the effect of a resource's coincidence with the risk of shortages, and models the limitations on availability, event duration, consecutive event days, and annual max event hours. It uses public data and relies on transparent, open-sourced, free code and models. The process is similar to LOLP weighted load impacts, with some main differences.

1. It uses historic net loads and scales wind, solar, and battery resources to create a risk allocation. As shown earlier, high net loads are closely related to the risk of resource shortage.
2. The risk allocation is granular. It defines with precision the hours and days when resources are most likely needed and the magnitude of the resource need.
3. It allows users to understand how different attributes influence the reliability contribution of the resource
4. It can better accommodate weather-sensitive resources
5. It can be used to model each DR resource independently or to model to the entire portfolio.

The figure below illustrates the main concept. We discuss each step in detail after we introduce the main concept.

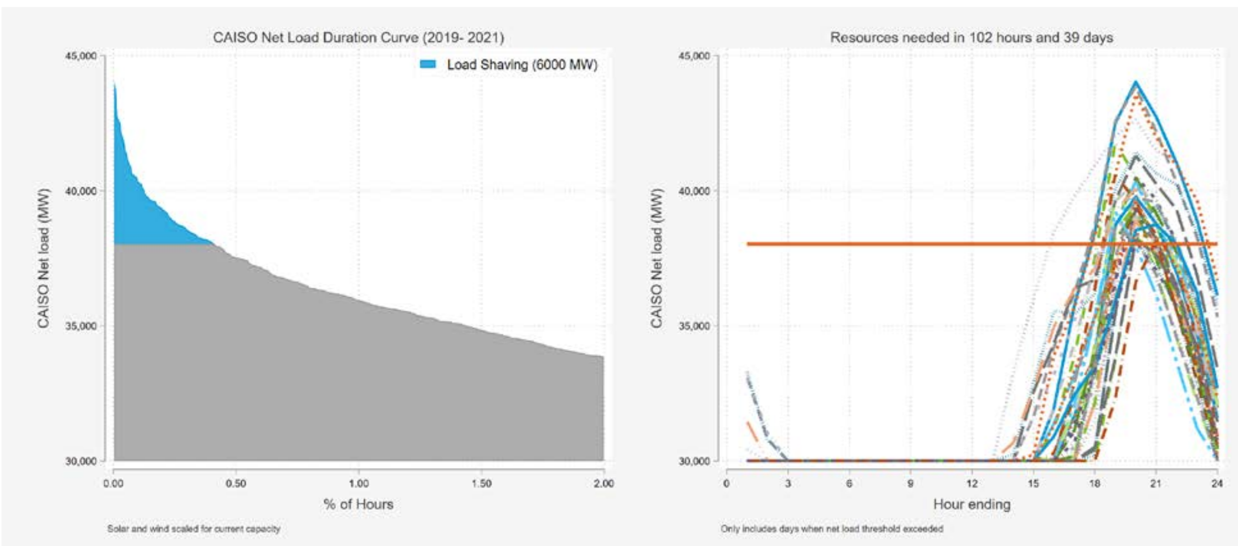


The main concept is that historical net load patterns, with adjustments, can be used to create a resource shortage risk allocation (a proxy for LOLP) directly tied to actual hours and days. Because the approach allocates the risk and depth of need to actual days and hours, it is possible to assess how good load shaving resources – solar and battery storage – are at shaving loads on the days and hours when resources are needed most.

Figure 7 illustrates the direct relationship between net loads and specific days and hours. But first, a few details. The solar and wind production patterns are real but scaled based on capacity to reflect the amount of installed capacity of the year in question. Thus, the net loads are adjusted to account for the interactive effects of solar and wind.[3] The amount of load shaving modeled is not arbitrary but tied to the nameplate capacity of load shaving resources, defined as demand response plus battery storage. As more load-shaving resources come online, the number of days and hours when those resources need to be dispatched to maintain reliability grows.

The below example uses 6,000 MW of load shaving resources, more than the total supply-side DR and battery storage currently on the system. In order to shave loads by 6,000 MW, resources would have needed to be dispatched on 39 days and 102 hours over the course of the three years modeled, as shown in the right panel. For each date and hour, the amount of load relief needed to shave the load duration curve is defined precisely. The example is an extreme example, intentionally reflected to demonstrate the effect of higher penetration of load shaving resources than currently exists. In practice, the amount of hours when resources are required would be less for individual years in part because the system is planned for 1-in-10 year conditions.

Figure 7: Shaving the Net Load Duration Curve is Directly Related to Specific Days and Hours



4.1 STEPS AND APPLIED EXAMPLES

The table below summarizes each of the steps in the Net Load ELCC proxy approach. The approach can be implemented via an online calculator connected to a statistical computing language (e.g., Python, R, Stata) that implements the calculations at the push of a button and produces all of the outputs shown below. Appendix A contains example draft code in Stata.

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[3] In practice, the adjustments are minimal. While the supply mix evolves over time, year-to-year changes in installed capacity are not extreme.

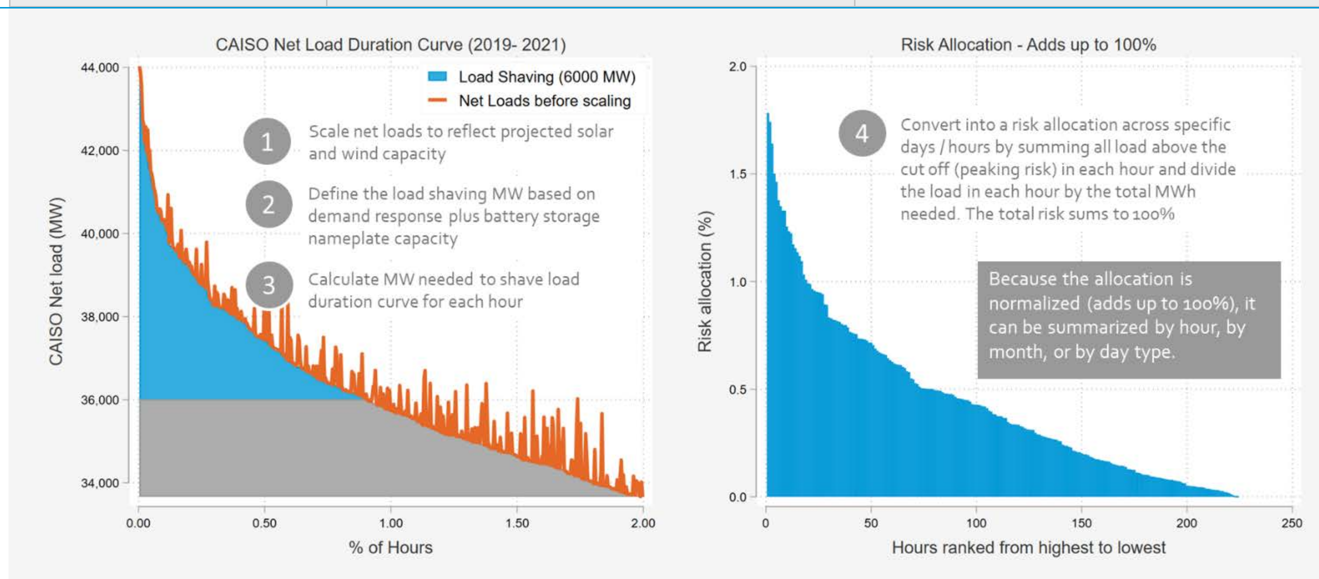
	Step	Example
1	**Collect standardized data on DR resources**	See Appendix B for detailed templates for weather sensitive and non-weather senstive resources. At a high level, the inputs are summarized below. The data inputs are intentionally structured so they can be converted into 8,760 houlry values of load reduction capability.

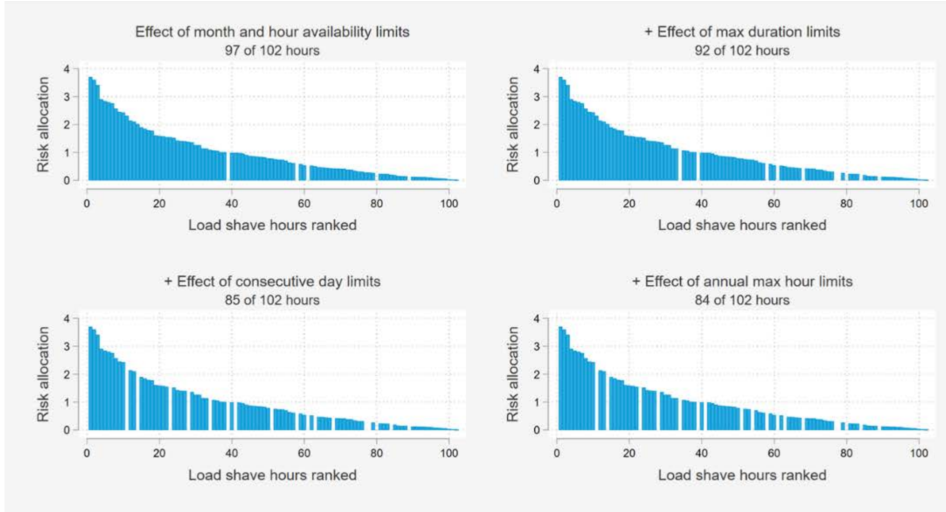
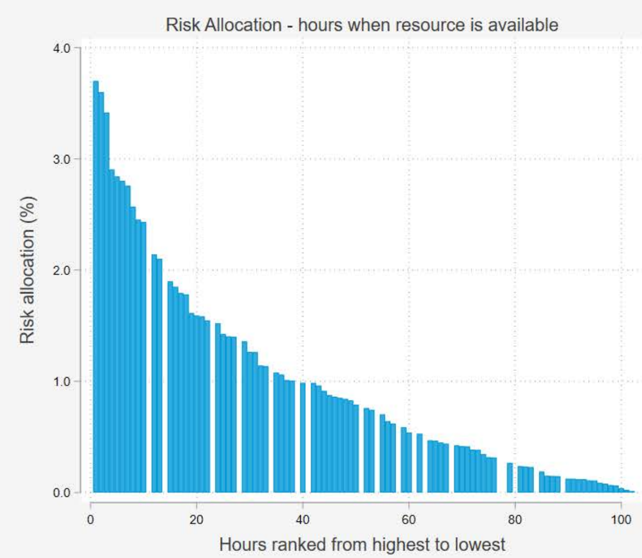
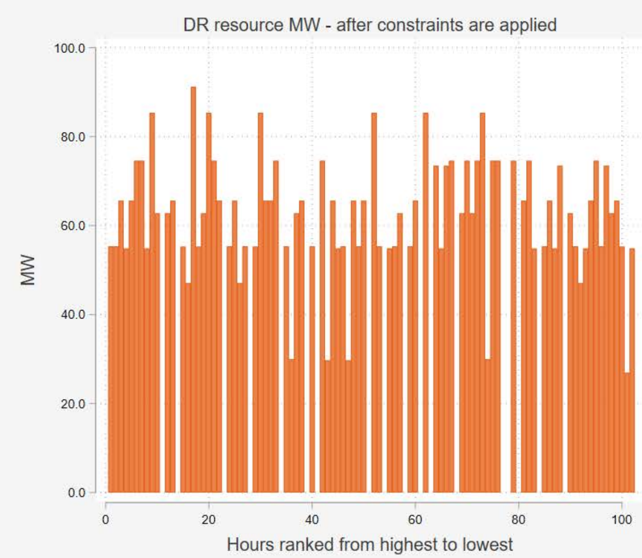
Component	Weather Sensitive Resources	Non-Weather Sensitive Resources
Load reduction capability (MW)	Table by hour of day and average daily temperature bins	Table by hour of day and month
Monthly and hourly availability	Table by month and hour indicating availability Net load threshold above which resource is available	Defined by load reduction table Net load threshold above which resource is available
Dispatch constraints	Max event duration Max number of consecutive event days Max annual hours	Max event duration Max number of consecutive event days Max annual hours

2 **Create a risk allocation using historical net loads and scaling for wind, solar, and battery storage.**

The risk allocation is a LOLP proxy (more technically, an EUE proxy) that reflects the depth of the need for resources. It used both to model constraints and to produce risk-weighted load.

$$Risk_t = \frac{mwover_t}{\sum_{t=1}^{n} mwover_t}$$



	Step	Example
3	**Assess the effect of availability constraints.** As noted earlier, each hour identified for load shaving is tied to a specific date and hour. Thus, we can sequentially layer limitations on monthly and hourly availability, max event duration, consecutive days, and annual hours.	 **DR Resource characteristics** ▪ Monthly availability: Apr-Oct ▪ Hourly availability: 12pm-10 pm ▪ Max event duration: 4 hours ▪ Max consecutive days: 3 ▪ Max annual hours: 50
4	**Calculate unadjusted ELCC (MW weighted by risk allocation)** The MW available for each hour, after applying the resource constraints, is multiplied by the resource shortage risk allocated to each hour and summed up. The result produces a risk-weighted MW that accounts for the coincidence of the resource with the risk of resource shortages. $$ELCC\ MW = \sum_{t=1}^{n} risk_t \cdot mw_t$$	 

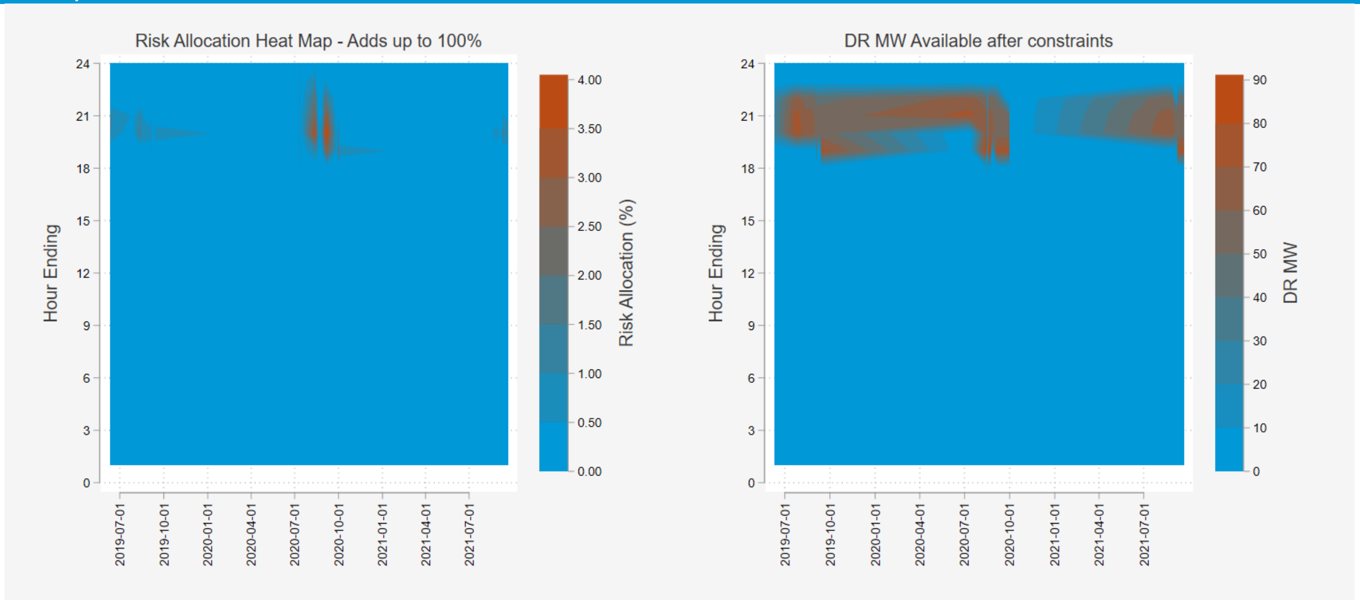
Step	Example
	

Figure 8 shows, step-by-step, the effect of the use limitations on example resource's contribution to reliability, which allows a user to identify how to adjust program rules or requirements in order increase the contribution to reliability. In addition, the model can produce hour-by-hour output that enables DR providers, regulatory, and consumer advocates to assess if the DR use limitations are applied correctly.

Figure 8: Example Impact of Use Limitations on Proxy ELCC

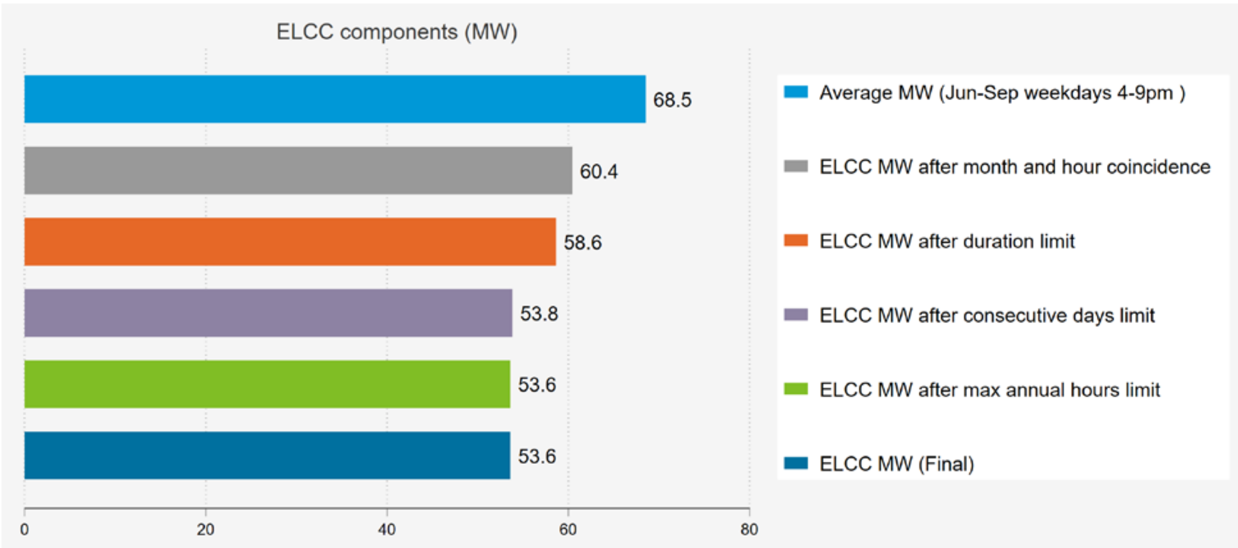


Table 1 shows how the number of days and hours with a risk allocation changes as the magnitude of load shaving resources grows. It reflects the reality that as the magnitude of load shaving resources grows, the resources will need be dispatched on more days and more hours in order to reduce or shave the demand.

Table 1: Impact of Load Shaving on the Amount of Hours and Days with Risk Allocation

Load Shaving MW	Risk allocation days (over 3-year period)	Risk allocation hours (over 3-year period)
3,000	7	15
4,000	13	31
5,000	27	57
6,000	39	102
7,000	58	157
8,000	86	242

Table 2 shows a sensitivity analysis summarizing how different levels of load shaving and different limitations on dispatch influence the results. All the iterations use the same resource with the same resource shape and month and hour of day availability. The starting value is less than 100% because the resource shape does not coincide perfectly with the timing of resource need. As the amount of load shaving resources grows larger, the contribution of the resource to reliability decreases. The resource needs to be used on more days, for more hours, and over longer durations as load shaving resources grow but cannot do so due to use limitations. As different use limitations are removed, the resources contribution to reliability increases.

Table 2: Sensitivity of Proxy ELCC to Load Shaving and Use Limitations

Load Shaving MW					
	Max event duration	4	4	4	6
	Max consecutive days	3	5	5	5
	Max annual hours	50	50	200	200
3,000		90.50%	90.50%	90.50%	90.50%
4,000		90.50%	90.50%	90.50%	90.50%
5,000		83.53%	87.14%	87.14%	88.14%
6,000		77.30%	79.83%	83.01%	85.34%
7,000		53.67%	48.75%	80.16%	82.75%
8,000		42.57%	44.43%	72.96%	75.01%

4.2 ALIGNMENT WITH WORKING GROUP PRINCIPLES

	Principle	How the proposal meets the principle
1	Transparent and understandable	The approach relies on public data, open-source code, and public models. Moreover, it produces the granular outputs which allow a user to verify the calculations and understand which factors most affect the resource's contribution to reliability
2	Best available information regarding resource capabilities, including recent historical performance and participant enrollment and composition projections	The approach incorporates the most recent historical performance and explicitly requires resources to define the limitations in a standardized manner.
3	Allow DR providers to quickly determine or update QC values.	The recommendation is to make the approach available in an online tool, in which case providers can quickly determine the QC values.
4	Consistent and compatible with the resource adequacy program a. Single-value RA program (status quo) b. Twenty-four-slice proposal (SCE) c. Two-slice proposal (Gridwell)	The approach is consistent with all three resource adequacy option. It can produce a single RA value, the evaluation load impact tables by month and hour can be directly employed in the 24-hour slice of day proposal. The approach can also be easily adjust to be consistent with the two-slice approach by modeling ELCC for net loads and gross loads.
5	Account for any use limitations, availability limitations, and variability in output of DR resources	The approach directly and transparently accounts for availability limitations by month hour, coincidence of DR with need, and limitations of max event duration, consecutive event days, and annual event hours.

6	Translate a DR resource's load reduction capabilities into its reliability value.	As shown in the examples, the approach convert the load reduction capabilities into a contribution to reliability value, accounting for the resources constraint and use limitations.
7	Include methods to determine delivered capacity (ex-post) that are compatible with the determination of QC (ex-ante)	The approach makes use of the existing DR load impact evaluation protocols, which require standardized reporting of performance during actual events (ex-post impacts) and require the standardized reporting of hourly demand reduction capability for standardized monthly system peak days conditions (ex-ante impacts). Moreover, the existing evaluation protocols require that, whenever possible, ex ante estimates of DR impacts should be informed by ex post empirical evidence from existing or prior DR resource options. Moreover, the approach DR providers to explicitly define availability and use limitations.
8	Not a substantial barrier to participation in the RA program.	The approach reduces and removes barriers to participation in the resource adequacy program. It reduces adding another step – use of LOLP models to estimate ELCC – that prolongs and complicates the QC process.
9	Account for a resource's capacity when reliability needs are highest	The approach accounts for capacity for monthly system peak days and the high net load periods when reliability needs are highest.

APPENDIX A: SUMMARY OF PROPOSED RESOURCE ADEQUACY FRAMEWORKS

The Resource Adequacy (RA) Slice of Day (SOD) Reform track Workshop Report was ordered in Decision 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 (SoD) proposal for resource adequacy (RA) reform. A series of ten online workshops were conducted from October 20, 2021, to January 19, 2022. The Two Slice Proposal from Gridwell and the 24-hours slide of day proposal from SCE are described below:

A) Gridwell - Two Slice Proposal Summary[4]

The Two Slice proposal has six key elements:

1. Maintain the monthly showing requirement and a single monthly Net QC (NQC) construct,
2. Perform a biannual 1-in-10 LOLE study to determine a system monthly RA Gross Load Requirement and a system monthly Net Peak Load Requirement,
3. Update the QC methodologies for all use-limited resources using Effective Load Carrying Capacity (ELCC) methodology and derate all thermal resources by historical ambient due to temperature-forced outages,
4. Add a monthly net load peak assessment to ensure sufficient capacity is available for no or low-solar hours, (Vistra proposal),
5. Maintain the CPUC penalty structure and penalize short Load Serving Entities (LSEs) 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.

B) SCE: 24-hours slide of day[5]

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

[4] Gridwell and Vistra's Two-Slice Proposal. Chapter-2_SOD-Proposal_Gridwell Consulting by Carrie Bentley and Cathleen Colbert

[5] Southern California Edison's Proposal for 24-Hourly Slice. Chapter-2_SOD-Proposal_SCE_24 Hourly Slices by Jeff Nelson, Brent Buffington

Component	SCE's 24-Hourly Slices Proposal[6]
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)
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

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

APPENDIX B: NET LOAD ELCC PROXY EXAMPLE DATA INPUT TEMPLATES

APPENDIX C: STATA CODE FOR NET LOAD ELLC PROXY ANALYSIS AND PLOTS

```
*==============================================================================
* 01. User Inputs
*==============================================================================

*A. Identify input, output, and load files
        global input_file "Inputs_Simplified_ELCC.xlsx"
        global load_data "../01_Assess_drivers_of_ELCC/$dir2/03_Drivers_of_ELCC_Analysis_dataset.dta"
        global  dr_mw   "$dir1/DR_MW_availability.dta"   // MW inputs expanded to 8760

*B. Identify Total Shave Amount and solar and wind capacity
        global shave_amount 7000
        global solar_cap   13000
        global wind_cap     7000

*C. DR availability constraints
        global dr_threshold 30000
        global max_daily_hours 6
        global max_annual_hours 200
        global max_consecutive_days 5

*==============================================================================
* 02 Detailed calcs for ELCC
*===============================================================================

*A. Import load data, scale renewables, and merge DR availability
        use "$load_data", clear
        keep year month ym weekday datetime date hour caiso_demand ///
                caiso_solar caiso_wind caiso_netload tempf avgtemp maxtemp
        tsset datetime, delta(1 hours)

        *Scale net loads for project amount of solar/wind in planning year

        *Merge DR availability
        merge m:1 weekday month hour using "$dr_mw", keep(1 3) nogen


        *Store DR "nameplate" values

        *Nameplate value - Average 4-9pm for Jun-Sep
        sum drmw if inrange(hour, 17, 21) & inrange(month,6, 9)
        global dr_nameplate = r(mean)

        *Max non-coincident value
        sum drmw
        global dr_max_nc = r(max)

        gen drmw_availability  = drmw


*B. Apply user threshold to DR availability
        replace drmw_availability = 0 if caiso_netload < ${dr_threshold}

*C. Calculate risk allocation
        sum caiso_netload
        global netloadpeak = r(max)
        global risk_threshold = ${netloadpeak} - ${shave_amount}
        gen risk_mwh = max(0,caiso_netload - ${risk_threshold})
        egen total_risk_mwh = total(risk_mwh)
        gen risk_allocation = risk_mwh / total_risk_mwh
```

```
*D. Apply duration constraint (continuous hours in day)
	/*Logic
		- Find window that maximizes DR MW availability x risk
		- Identify start and end_times
		- Limit ELCC calculation to only inlcude those hours
	*/
	*01 Find window that maximizes DR MW availability x risk
		gen interimcalc_1  = risk_allocation*drmw_availability
		tssmooth ma ma_interimcalc_1 = interimcalc_1, ///
			window(0 1 `= ${max_daily_hours}-1')
		egen  max_interim = max(ma_interimcalc_1), by(date)

	*02 Identify dispatch start and end times
		gen double dispatch_start_temp = datetime if (max_interim == ma_interimcalc_1 )
		egen double dispatch_start = max(dispatch_start_temp), by(date)
		gen dispatch_hours_duration = inrange(datetime, dispatch_start, dispatch_start+
${max_daily_hours}*60*60*1000 )
		gen drmw_duration = drmw_availability * dispatch_hours_duration


*F. Apply consecutive days constraint
	preserve
		*Identify event days
		egen eventday = max(drmw_duration > 0 ), by(date)

		*Switch to daily
		collapse (max) eventday, by(date)
		tsset date

		*Calculate rolling window of eventdays
		local condition = 0
		local iter = 0
		while `condition' == 0 & `iter' <=10  {
			local iter  = `iter' + 1

			*Calculate consecutive event days
			tsspell eventday
			sum _seq if eventday == 1

			*Is condition met?
			local condition = (r(max) <= ${max_consecutive_days} )

			*If condition not met introduce a gap on max day + 1
			if `condition' == 0 {
				replace eventday = 0 if _seq ==  ${max_consecutive_days} +1
			}
			drop _*
		}

		*Save in temporary file
		label variable eventday "Event days after applying consecutive days constraints"
		tempfile eventdays
		save `eventdays', replace
	restore

	merge m:1 date using `eventdays', keep(1 3) nogen
	gen drmw_consecutivedays = drmw_duration * eventday
	drop eventday

*G. Apply Max Annual event hours constraint
	gen eventhour = drmw_consecutive >0
	bysort year (datetime): gen total_hours = sum(eventhour)
	replace total_hours = 0 if eventhour == 0
	replace eventhour = 0 if total_hours > ${max_annual_hours}
	gen drmw_annualmaxhours = drmw_consecutivedays * eventhour

*H. Calculate drop off
	gen risk_availability =  risk_allocation *(drmw_availability>0)*100
```

```
        gen risk_duration = risk_allocation * (drmw_duration>0) * 100
        gen risk_consecutivedays = risk_allocation * (drmw_consecutivedays>0) *100
        gen risk_annualmaxhours = risk_allocation * (drmw_annualmaxhours>0) * 100

*H. Clean up, label, and save
        drop total_risk_mwh interimcalc_1 ma_interimcalc_1 ///
                max_interim dispatch_start_temp dispatch_start dispatch_hours_duration total_hours
        gen drmw_elcc_calcs = drmw_annualmaxhours
        gen resource_needed  = risk_allocation >0
        gen resource_dispatched = eventhour

        label var risk_mwh "MWh needed to shave load duration curve"
        label var risk_allocation "Risk allocation (adds up to 100%)"
        label var drmw_availability  "DR MW after availability constraints"
        label var drmw_duration  "DR MW after availability and duration constraints"
        label var drmw_consecutivedays  "DR MW after availability, duration, and consecutive day
constraints"
        label var drmw_annualmaxhours "DR MW after availability, duration, consecutive days, and max
annual hour constraints"
        label var drmw_elcc_calc "DR MW after all constraints"
        label var risk_availability "Effect of month and hour availability limits"
        label var risk_duration "+ Effect of max duration limits"
        label var risk_consecutivedays "+ Effect of consecutive day limits"
        label var risk_annualmaxhours "+ Effect of annual max hour limits"

*I. Save and export
        order year- caiso_netload risk_mwh risk_allocation drmw_*
        sort datetime
        label data "Unique index: datetime"
        save "$dir3/Detailed_calculations_for_ELCC.dta", replace



*================================================================================
* 03 Produce ELCC
*=================================================================================

*A. Calculate interim values
        use "$dir3/Detailed_calculations_for_ELCC.dta", replace
        foreach var of varlist drmw_*  {
                replace `var' = `var' * risk_allocation
        }

*B. Calculate ELCC values step by step
        collapse (sum) drmw_*
        gen drmw_nameplate = $dr_nameplate
        order  drmw_nameplate, first

*C. Clean up and save
        label var drmw_nameplate  "Average MW (Jun-Sep weekdays 4-9pm )"
        label var drmw_availability  "ELCC MW after month and hour coincidence"
        label var drmw_duration  "ELCC MW after duration limit"
        label var drmw_consecutivedays  "ELCC MW after consecutive days limit"
        label var drmw_annualmaxhours "ELCC MW after max annual hours limit"
        label var drmw_elcc_calcs "ELCC MW (Final)"

        save "$dir3/ELCC_summary.dta", replace

*================================================================================
* 04 Produce Graphs
*=================================================================================

*A. Produce ELCC drop of graph
        use "$dir3/ELCC_summary.dta", replace
        graph hbar (asis) drmw*,                                   ///
                name(elcc_bar, replace)                                     ///
                title("ELCC components (MW)")            ///
                bargap(50) blabel(bar, format(%5.1fc))  ///
                legend(pos(3) rows(6) rowgap(*7.0))
```

```
*B. Load shaving
	use "$dir3/Detailed_calculations_for_ELCC.dta", replace
	gen mw_below_cutoff = min(caiso_netload, $risk_threshold)

	gsort -caiso_netload
	gen pct_of_hours = _n/_N *100
	label var pct_of_hour "% of Hours"
	sum caiso_netload if pct_of_hours>=5
	global min_plot = floor(r(max)/5000)* 5000
	sum year
	local yearmin  = r(min)
	local yearmax  = r(max)

	twoway  (area caiso_netload pct_of_hours)        ///
		(area mw_below_cutoff pct_of_hours)      ///
		if pct_of_hours<=2,                                     ///
		name(load_duration, replace)                    ///
		plotregion(fcolor(white))                               ///
		ytitle(CAISO Net load (MW)) ylabel(, format(%8.0fc))  ///
		xlabel(, format(%5.2fc)) ///
		title(CAISO Net Load Duration Curve (`yearmin'- `yearmax'))  ///
		legend(ring(0) pos(2) order(1 "Load Shaving (${shave_amount} MW)")) ///
		caption("Solar and wind scaled for project installed capacity", size(*0.7))

*C. Load Shave days (hourly profile)
	use "$dir3/Detailed_calculations_for_ELCC.dta", replace
	egen day_risk_allocation = total(risk_allocation), by(date)
	keep if day_risk_allocation>0
	egen daily_netpeak  = max(caiso_netload), by(date)
	gsort hour -daily_netpeak
	by hour: gen rank_daily =_n
	sum rank_daily if risk_allocation>0
	local days = r(max)
	local hours = r(N)


	*Create labels (for reshape)
	levelsof rank_daily, local(ranks)
	foreach r of local ranks {
		sum date if rank_daily == `r'
		local d = r(mean)
		local label`r' = ///
			string(`r', "%02.0f") + " " ///
			+ string(year(`d'))  + "-"  ///
			+ string(month(`d'), "%02.0f")   + "-"  ///
			+ string(day(`d'), "%02.0f")
		display "`label`r''"
	}

	*Reshape
	keep hour rank_daily caiso_netload
	replace caiso_netload  = max(${min_plot}, caiso_netload)
	rename caiso_netload =_
	reshape wide caiso_netload_, i(hour) j(rank_daily)
	foreach r of local ranks {
		label var caiso_netload_`r' "`label`r''"
	}

	gen load_shave = $risk_threshold
	label var load_shave "${shave_amount} MW Reduction"

	*Plot it
	if `days' <=15 {
		local legend "legend(pos(4) rows(15))"
	}
	else {
		local legend "legend(off)"
	}
```

```
        twoway (line caiso_netload* hour) ///
                (line load_shave hour, lpattern(solid) lcolor("230 100 30") lwidth(*1.2)) ///
                , name(shavedays, replace) ///
                plotregion(fcolor(white)) ///
                title(Resources needed in `hours' hours and `days' days) ///
                ytitle(CAISO Net load (MW)) ylabel(, format(%8.0fc))  ///
                xlabel(0(3)24) xtitle("")  xtitle(Hour ending) ///
                `legend'  ///
                caption("Only includes days when net load threshold exceeded", size(*0.7))

*D. Combine
        graph combine load_duration shavedays, name(shaving, replace) cols(2) ycommon scale(0.9)


*E. Plot effect of constraints
        use "$dir3/Detailed_calculations_for_ELCC.dta", replace
        gsort -caiso_netload
        gen pct_of_hours = _n/_N *100
        gen rank_hours = _n
        label var pct_of_hour "% of Hours"
        label var rank_hours "Load shave hours ranked"

        keep if risk_allocation > 0
        replace risk_allocation = risk_allocation*100
        keep year-hour caiso_netload risk_* rank_hours pct_of_hours
        drop risk_allocation risk_mwh*

        *Plots
        foreach var of varlist risk_* {
                local title: variable label `var'
                sum `var' if `var'>0
                local hours_txt  "`=r(N)' of `=_N' hours"

                twoway (bar `var' rank_hours, sort)  ///
                        , name(`var', replace) plotregion(fcolor(white)) ///
                        title("`title'") subtitle("`hours_txt'") ///
                        ytitle(Risk allocation)
        }

        graph combine risk_availability risk_duration risk_consecutivedays risk_annualmaxhours
```