DOCKETED	
Docket Number:	22-RENEW-01
Project Title:	Reliability Reserve Incentive Programs
TN #:	250099
Document Title:	Cliff Staton - Joint Parties Comments on Demand Side Grid Support Revised Program Guidelines
Description:	N/A
Filer:	System
Organization:	Cliff Staton (Filing for Joint Parties)
Submitter Role:	Public
Submission Date:	5/11/2023 9:59:34 AM
Docketed Date:	5/11/2023

Comment Received From: Cliff Staton (Filing for Joint Parties)
Submitted On: 5/11/2023
Docket Number: 22-RENEW-01

Joint Parties Comments on Demand Side Grid Support Revised Program Guidelines

Additional submitted attachment is included below.

California Energy Commission
Docket No. 22-RENEW-01 - Reliability Reserve Incentive Programs

OhmConnect, Inc., Google Nest, and Voltus, Inc., collectively the "Joint Parties", respectfully submit these comments in response to the Second Edition of the Proposed Program Guidelines for the Demand Side Grid Support (DSGS) program.

The Joint Parties wish to express our appreciation for the CEC's open and inclusive stakeholder process in developing the Revised Guidelines, and we look forward to the implementation of the program in Summer 2023. Vice Chair Gunda and Staff have done an outstanding job of engaging stakeholders and incorporating feedback into the proposed revised DSGS guidelines – all under challenging time pressure in advance of Summer 2023.

We appreciate the inclusion in the proposed revised DSGS guidelines of recommendations from the Joint Parties as reflected in Incentive Option 2 of the Revised Guidelines for the Demand Side Grid Support program. Incentive Option 2, "Incremental Market-Integrated DR Capacity," provides incentive payments for demonstrated capacity in excess of Resource Adequacy (RA) capacity commitments. The Joint Parties support Incentive Option 2, and believe the incentive payments will support growth of the DR resource and, in turn, help stabilize the grid.

In the remainder of these comments, we propose four adjustments that will encourage investment in emergency DR capability in California and thereby improve summer grid resiliency:

1. Increase the incentive rate for Incentive Option 2 to more accurately reflect current and recent pricing conditions in the California RA market;
2. Expand the time horizon over which the DSGS statistical analysis is performed to ensure inclusion of extreme weather events;
3. Establish a measure of temperature that accurately reflects the weather conditions experienced by end-customers during DR events; and
4. Remove the requirement that DR Aggregators obtain written permission from CCAs and POUs in order to enroll customers in the program.

1. Increase the DSGS incentive rate for Incentive Option 2 to reflect the current RA market conditions

We are concerned that the level of incentives proposed for Option 2 is significantly below current RA market prices and thus will not achieve the desired policy objective. Incentive levels that are consistent with and based on current market prices would better support both grid reliability and the growth of the DR resource.

In response to a question during the April 26th DSGS Workshop, CEC Staff noted that the Option 2 incentive levels on page 11 of the Revised Guidelines are based on the 2021 Resource Adequacy Report[1] published by the California Public Utilities Commission ("CPUC") in April 2023. Although the 2021 RA Report was just published last month, the price data on which the report is based dates back to 2019-2020. The Report outlines the methodology used to determine RA prices:

> *"Energy Division issued several data requests to all CPUC-jurisdictional LSEs requesting monthly capacity prices paid by (or to) LSEs for every RA capacity contract executed during 2020, 2021, and 2022 for use in calculating the Power Charge Indifference Adjustment (PCIA) RA adder and this RA price analysis. Energy Division received responses from all LSEs. With the exception of Table 6, which includes contracts executed through Q3 of 2021 for delivery in 2021-2023, **data used in this analysis were restricted to contracts executed in 2019 or 2020 for delivery in 2021**."*[2] (Emphasis added)

This means that DSGS incentives for 2023 and beyond are being based on market data that is three to four years old – prior to the COVID pandemic, prior to the war in Ukraine, and prior to persistent inflation in the U.S. economy over the last few years.

A steady upward trend in RA prices was already evident during the 2017-2021 period, as outlined in the 2021 RA Report. This chart below, from page 29 of the 2021 RA Report, illustrates that trend well.

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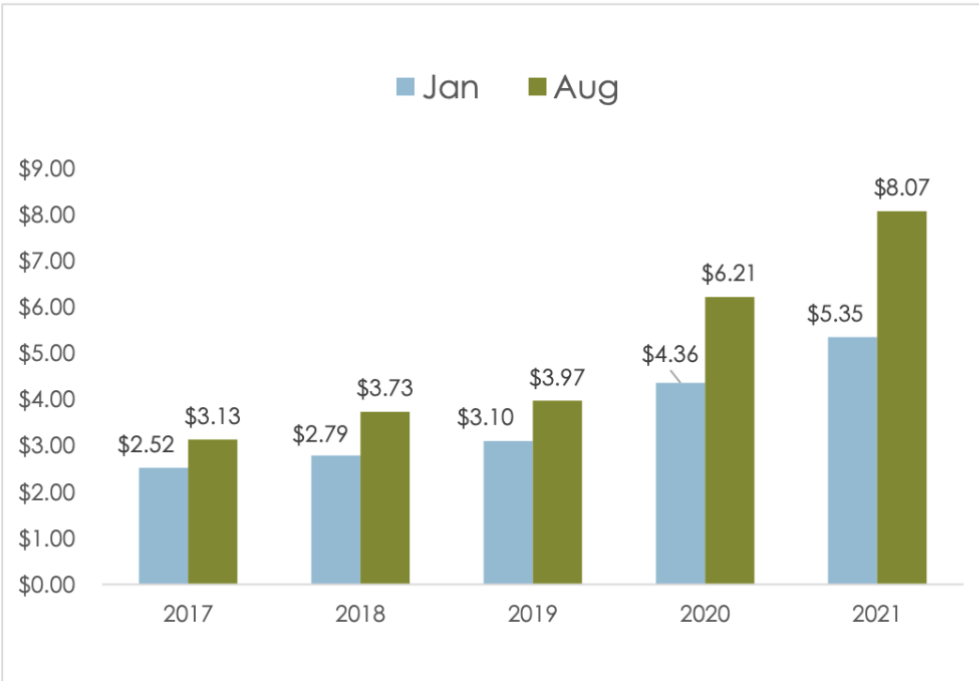
[1] https://www.cpuc.ca.gov/RA/

[2] 2021 Resource Adequacy Report, pp 24-25.

According to the authors of the RA Report, “these price increases appear to be driven by issues related to supply and demand balances to resource retirements, load forecast increases, and changes to counting conventions for certain resources.”[3]



Source: 2017-2021 price data submitted by LSEs.

Figure 1: Weighted Average Price of System RA ($/kW-month), January and August 2017-2021

Although the Joint Parties were unable to conduct a similar survey of all CPUC-jurisdictional LSEs for the purpose of these comments, current price information was obtained from brokers who are active in the California RA market. That data shows that RA prices escalated even more dramatically in 2022 and 2023:

[3] Ibid, p. 28

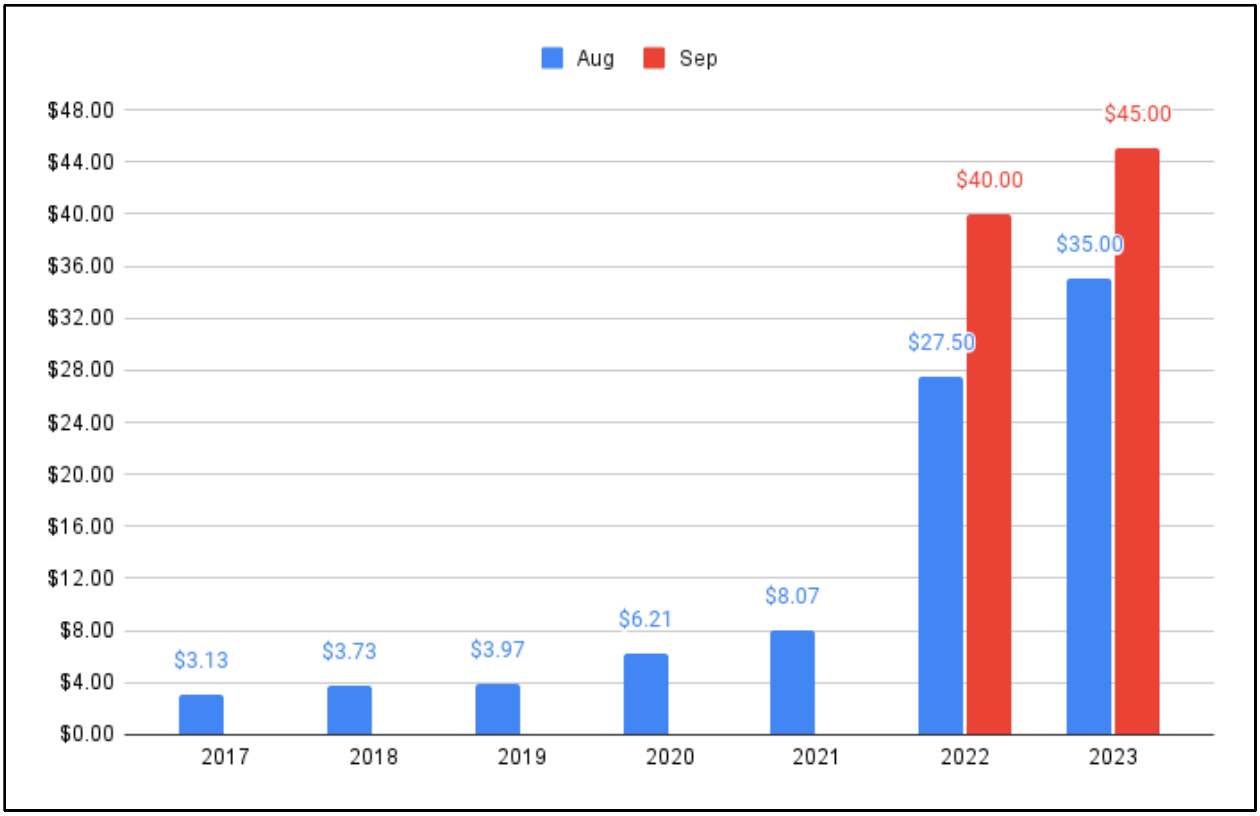


Figure 2: **California RA market pricing trends: 2017-2023 ($/kW-month)**
Source: 2021 CPUC RA Report (2017-21 data); Calif. RA brokers (2022-23 data).

The 2021 RA Report notes that prices vary significantly by month. Figure 1, above, shows prices for January and August – the low and high water marks for 2017-2021. In recent years, however, prices for September (Figure 2) have been higher than August – reflecting changes in weather and peak stress on the grid. The CEC's Integrated Energy Policy Report documents the trend of higher September peak load.[4] For that reason, we have included price information from September.

Since the prices from the 2021 Resource Adequacy Report do not reflect current market conditions, the question becomes how should CEC best determine incentive levels that reflect the current market. We offer two possible approaches:

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[4] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report/2021-1. See, for example: CED 2021 Hourly Forecast - CAISO - Mid Baseline - AAEE Scenario 2 - AAFS Scenario 4

- Base incentive levels on prices in the 2021 Resource Adequacy Report and create a metric to adjust for subsequent price inflation. For example, the RA Report shows weighted average prices, and also shows prices in the 85th percentile. The incentive amounts could be based on the 85th percentile, boosted by 50% or more in order to account for inflation.

- Conduct a brief survey of CPUC-jurisdictional LSEs upon which to base incentive levels. CEC could survey all CPUC-jurisdictional LSEs, asking for price information on their most recent 10 deals for 2023. The incentive levels could then be based on the weighted average of those 10 deals.

Comment 1 Conclusion: To achieve the desired policy objective of increasing grid reliability and growth of the DR resource, it is important that incentive levels are increased to be consistent with current market prices.

2. Extreme weather uncertainty and investment risk should not be solely borne by third-party DRPs

We want to raise a separate concern related to the substantial financial risk assumed by Demand Response Providers (DRPs) who build and maintain DR resources – which can only be partially compensated by DSGS if and when there is an extreme weather event.

The Revised Guidelines propose to use data for only the current year to estimate bid-normalized load impact (BNLI) profiles and Demonstrated Capacity (DC) for the purpose of calculating DRPs' DSGS Incentive Option 2 payments. We recommend that DRPs have the option to estimate BNLI profiles and DC using data for multiple years insofar as such data is available from the CAISO. For example, if a DRP has participated in the CAISO market since 2020, it may elect to estimate its BNLI profiles and DC values for summer 2023 using data for the entire 2020-2023 period.

This proposed simple change appropriately redistributes some risk from individual DRPs to the State. DRPs will incur significant costs to build and maintain DR resources capable of providing incremental load relief in the event of extreme weather. Under the current proposal, however, DRPs will not recoup any of these costs if extreme weather does not occur in the current year – something that is completely outside of DRPs' control.

A multi-year dataset is more likely to include at least one extreme weather event and thereby provides a statistically-informed estimate of a DRP's load curtailment capability in the event of extreme weather, even if extreme weather does not occur in the current year. In this manner, estimating BNLI profiles and DC using multiple years of data reduces the risk that DRPs' investments are stranded, consistent with AB 205's requirement that DSGS "incentivize dispatchable customer load reduction [...] for the state's electrical grid during extreme events."

Comment 2 Conclusion: To achieve the desired policy objective of increasing grid reliability and growth of the DR resource, the BNLI profiles and DC should be estimated using multiple years of available data from the CAISO to incentivize DRPs to build and maintain resources capable of providing incremental load relief.

3. Temperature metric should reflect weather conditions experienced by DR participants

The DSGS Incentive Option 2 regression model includes a variable, Temp, for the "average of daily high and low temperature for a representative sub-LAP weather station". However, the Revised Guidelines do not specify how this regressor is to be calculated from available data. Sub-LAPs span large geographic areas within which there can be considerable variation in temperature at any given time. The temperature data used to estimate DRPs' BNLI profiles and DC values should reflect as accurately as possible the weather conditions actually experienced by end-customers on the date of a DR event. Therefore, CEC Staff should identify a methodology for calculating sub-LAP-level temperature using publicly-available weather station data (e.g. from NOAA) and end-customer location data accessible to the CEC via the CAISO's Demand Response Registration System (DRRS).

4. Requiring written permission to enroll customers from CCAs and POUs is unnecessarily burdensome and could dramatically limit the load reduction impact of the DSGS program.

In Chapter 2, Eligibility and Participation, the Revised Guidelines state: “Before enrolling customers in the service territory of a local publicly owned electric utility (POU), or community choice aggregator (CCA), aggregators of customers must receive written permission from each applicable POU or CCA to participate in the DSGS program.”

There are currently 24 CCAs in California. From an administrative standpoint alone, this is an unnecessarily burdensome requirement for Aggregators. It should be the customer’s choice to join the DSGS program of a third-party Aggregator, or the CCA. Requiring the Aggregator to obtain the permission from the CCA is characterized as an administrative task but will likely have an anti-competitive effect.

Quite apart from the administrative burden, this requirement is likely to dramatically limit the effectiveness of the DSGS program. The CEC is not expected to vote on the Revised Guidelines until its June 16, 2023 meeting. Under the best of circumstances, it could take months to obtain written permission from all 24 CCAs in California. According to the Revised Guidelines, an aggregator must submit written authorizations from CCAs as part of its “Application Package.” If some CCAs don’t provide written authorization – due to oversight, lack of prioritization of response, or opposition – the Aggregator may not be in a position to submit the Application Package until after a summer 2023 heat wave – which would undermine the purpose and intent of the DSGS program.

This requirement also runs counter to CAISO rules governing DR resources. CAISO market settlement rules allow customers from CCAs and IOUs to be commingled in a DR resource.[5] By requiring an Aggregator to obtain written permission from each CCA

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[5] CAISO’s *Business Practice Manual for Demand Response* (Version 10) states: “End-use customers (Service Accounts) can be aggregated across multiple LSEs in a [PDR] registration, but they must be in the same sub-LAP.”

in order to enroll customers in the program, the DSGS Guidelines will in effect force Aggregators to abide by two sets of regulatory requirements.

We recommend that, rather than requiring written permission from each CCA, the Aggregator must simply notify the CCA, similar to the requirement for IOUs that is stated in the Revised Guidelines.

We appreciate the CEC's thoughtful approach to developing the revised DSGS guidelines in advance of summer 2023 and appreciate your consideration of the Joint Parties' recommendations. We look forward to working with agency staff to implement the program, enhance grid reliability, and expand the in-state DR resource.