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California Efficiency + Demand Management Council Corrected Comments on June 25 California Energy Commission Load Shift Goal Workshop

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I. Introduction

The California Efficiency + Demand Management Council ("Council") appreciates this opportunity to provide its corrected comments on the June 25 *Integrated Energy Policy Report ("IEPR") Commissioner Workshop on California's Progress Toward the Load-Shift Goal* ("LSG Workshop").

II. Council Comments

A. Demand flexibility should be reliable and predictable while recognizing the variable nature of load.

One of the key messages that was delivered in the opening remarks by the attending agency commissioners was that demand flexibility should be reliable and predictable. The Council agrees with this standard but cautions that "reliable and predictable" will inevitably have different meanings to different people. As a foundational principle, it is critical that all agencies understand that load is variable in that it cannot be perfectly predicted. This is why, in the California Independent System Operator ("CAISO") market, generation resource production is constantly being adjusted to match the real-time system load. If it was possible to perfectly forecast load, the real-time market would be unnecessary. Fundamentally, this load variability limits the precision of forecasting the amount of load that can be shed or shifted at any point in time. At a high level, this imprecision is largely due to behavioral and weather-dependent characteristics. The California Public Utilities Commission ("CPUC") recognized this in Decision ("D.") 21-06-029, stating, "[Demand response] is a variable resource with behavioral and weather-dependent characteristics and DR should be treated as such in CAISO's markets."[1]

In spite of this variability, it is possible to predict, within a certain margin of error, the load impacts of demand flexibility. This margin of error is evident in the ex post and ex ante

[1] D.21-06-029, at Finding of Fact 5.

analyses contained within the annual Demand Response Load Impact Reports provided by investor-owned utilities ("IOUs") and third-party demand response ("DR") providers. However, any expectation that demand flexibility is, or should be, as precise as a conventional generator is unrealistic and overlooks the great deal of value that can be provided by more closely matching demand to generation, something that was highlighted by CPUC Commissioner Houck during her opening remarks.

B. Coordination across agencies should be formal and transparent.

The Council was very encouraged by the supportive remarks of California Energy Commission ("CEC") Commissioner McAllister and CPUC Commissioner Houck regarding the need for interagency collaboration. The Council sees this as the single most important condition to meeting the LSG. The CEC has the legislative mandate to develop and adopt the LSG but it cannot be met without formal adoption by the CPUC because most of the regulatory issues that impact the LSG are under CPUC jurisdiction. More specifically, the CPUC should open a new DR rulemaking to adopt the LSG and consider the necessary policy changes to unlock the vast potential of demand flexibility in the state. These include:

1. <u>A detailed and realistic roadmap for reaching the LSG:</u> A plan is needed that addresses how the LSG will be achieved, including the necessary policies, and allocation among various types of demand flexibility (e.g., dynamic rates and other types of load modifying DR, supply side DR) and responsible load-serving entities ("LSEs")).
2. <u>A streamlined DR Net Qualifying Capacity ("NQC") counting methodology:</u> The current process by which distributed energy resource ("DER") providers receive resource adequacy ("RA") values for their portfolios discourages their participation in the RA market. This process is long and resource-intensive, very opaque, and often results in substantial discounting of ex ante values, with no explanation given. It is possible that the recent heavy discounting of ex ante values is a contributing factor to the rapid fall in supply side DR resources that was cited during the workshop. Stakeholders, and the CEC and CPUC staff have developed an incentive-based DR NQC counting methodology over the past several years that would be easier to utilize and more transparent, and would directly link underperformance to penalties. The CPUC should finalize this methodology and consider its approval.
3. <u>An NQC counting methodology for exporting behind-the-meter ("BTM") energy storage:</u> The absence of a framework for recognizing the NQC value of exporting behind-the-meter ("BTM") energy storage has stranded hundreds of MW of valuable capacity. The CAISO is already investigating mechanisms to allow BTM storage exports in the wholesale market, so CPUC action on quantifying their NQC value is a critical piece of cross-agency coordination that should take place in the near future. Parties have put forth two different NQC counting proposals in past RA proceedings that can serve as a good starting point.
4. <u>Rules governing device-level measurement:</u> As several stakeholders mentioned in their response to the CEC's stakeholder survey, using performance measurement features that are integrated into enabling technologies can be used to directly measure a customer's

performance in a DER program rather than only relying on utilizing the customer's meter data. This would streamline the provision of data for DR participation and improve the accuracy of performance measurement for certain devices.

5. <u>Reexamination of DR dual participation rules, including the potential for BTM energy storage and electric vehicles ("EV") to provide supply side and load modifying DR:</u> The CPUC should allow customers with multiple smart technologies to participate in separate DER programs and with separate DER providers. Developing a framework for this would enable each participating customer's enabling technology to be used when it can deliver the most demand flexibility.
6. <u>More equitable treatment between IOU and third-party demand flexibility programs, including testing requirements and access to enabling technologies:</u> Customers participating in third-party DR programs are ineligible to receive technology incentives through the Automated Demand Response ("AutoDR") program and the statewide Self-Generation Incentive Program ("SGIP"). This demotivates participation with DER providers and forgoes the opportunity of existing third-party customers to achieve greater and/or more reliable load curtailment during DR events. It also reduces competition in California's DR sector by preferencing IOU-run DR programs, which blocks innovation and discourages new companies from entering the state.
7. <u>Expanded eligibility for DR programs to provide RA capacity outside the Availability Assessment Hours ("AAH"):</u> The Slice of Day ("SoD") RA framework requires LSEs to procure RA capacity to meet hourly RA requirements. As a resource that can typically only operate for up to four hours at a time, DR is ideal for meeting RA requirements for one or a handful of hourly slices.
8. <u>Recognition of qualifying CEC demand flexibility programs in the RA regime if they are not reflected in the CEC load forecast:</u> All demand flexibility programs, regardless of whether they are CPUC or CEC jurisdictional, that meet the CPUC's minimum requirements to qualify as an RA resource, should be recognized and counted as such to ensure that those funding these programs are receiving full value for their contributions.
9. <u>Reducing the four-hour minimum dispatch duration for DR resources:</u> The CPUC's RA rules require that DR resources must be capable of four-hour dispatches to qualify as RA capacity. However, the load impacts of some DR are greatest for two hours, with the load impacts trailing off during the remaining two hours. This phenomenon is often seen in DR backed by smart thermostats. With the hour-specific RA requirements under the SoD RA framework, a four-hour minimum dispatch is no longer necessary to solely meet the system peak hour. DR resources should be allowed to provide RA for fewer than four hourly slices.
10. <u>Reforms to the customer data access ("CDA") rules including a centralized customer data model, similar to Smart Meter Texas or the Danish DataHub:</u> CDA continues to be a major barrier to third-party DER providers enrolling customers and managing their participation in the CAISO market. The customer authorization process to share meter data with DER providers is unreliable to the point that a majority of customers fail to

complete it.[2] Also, the quality and timeliness of these data are often inadequate which creates a poor customer experience and inhibits the efforts of DER providers to improve performance. In fact, PG&E has acknowledged the problematic nature of the ShareMyData process while defending its Automated Response Technology ("ART") Program, stating that its "requirements for customer registration in the ART are notably less arduous than other DR programs already approved to enroll SGIP participants and third-party RA contract process." [footnote omitted][3] A less arduous data authorization process should be available to all customers, regardless of their program and DER provider.

11. Explore alternative program models to simplify and improve demand flexibility program participation: California should leverage the innovative ideas of other states and countries, such as the Massachusetts ConnectedSolutions, New York VDER Tariff, and the Danish Energinet, that have successfully led to large amounts of demand flexibility.
12. One or more baseline methodologies that incentivize customers to deploy their demand flexibility for the greatest system benefit: Program rules, including around dual participation, baseline methodologies, and penalties, create a fundamental incompatibility between two of the largest financial factors incentivizing customer load flexibility – managing on-bill costs (i.e., demand management charges) and providing DR capacity. For instance, if a customer installs a BTM battery to manage on-bill costs, the customer will most likely be compensated less (or even penalized) within the RA or DSGS programs, because using that battery to provide exactly the desired shifting the LSG has in mind will result in a diminished load baseline (if using day-matching, the most frequently utilized baseline methodology by far). Often the customer will choose not to participate at all in a capacity program so as to not risk missing out on the larger financial benefits of demand management. This leaves a lot of existing load flexibility unused.

C. Central data repository should be updated more frequently

During the workshop, CEC Commissioner McAllister provided a helpful update on the CEC's central data repository – the CEC is receiving IOU customer smart meter data on a quarterly basis, which they are then cleaning and archiving. There are many potentially useful applications of its database that it should consider, especially if the data can be collected and made available much more frequently.

At a higher level, the May 22 California Demand Flexibility Summit provided an excellent 60-minute prerecorded presentation on Enabling SmartGrid Innovation. Topics covered included: categories of data; the differences between traditional, transactional events and

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[2] The Council submitted detailed comments on this issue in its January 31, 2024 comments on the CEC's January 17, 2024 workshop on Load Management Standards Implementation.

[3] Reply to the Protest of Leapfrog Power, Inc. to Advice 7577-E – PG&E Advice Letter to Update Eligible Demand Response Program Lists to Include the Automated Response Technology Program, in Compliance with D.23-12-005 and D.24-03-071, May 19, at p. 2.

sensor time-series data; use case possibilities; and drivers, hurdles, and high impact areas.[4] More immediately, one key application is to develop universal matched comparison groups that can be used by all IOU and non-IOU demand flexibility providers. This would ensure a consistent DER performance measurement approach. However, updates to the data repository would need to occur far more frequently than today to allow for market settlement. In the near term, an alternative approach that would not require more frequent data updates could be to develop prescriptive baselines, i.e. using that historical load data to develop static baselines for different technologies or customer types under different conditions. With enough data on historical customer usage, it is feasible to develop accurate counterfactuals for large aggregations of DR participants. These are already being used in the Demand Side Grid Support ("DSGS") Program to streamline performance measurement and settlement for BTM batteries. The Council also notes that OpenDSM, an open-source suite of models that has been deployed in California since 2016, can utilize these data to measure demand flexibility program performance.

However, if the CEC's centralized repository were updated more frequently, it could not only be used to create universal matched comparison groups but potentially offer a new, centralized platform by which third-party providers could access consenting customers' data, eliminating key bottlenecks in customer enrollment. Currently, DR providers must navigate IOU data access processes that are administratively burdensome, requiring customers to authorize data sharing by inputting utility-specific login credentials. These processes create friction at enrollment, delay program participation, and limit the ability of providers to accurately and efficiently assess performance. By centralizing settlement through a CEC data platform, the state could implement modern, standardized, and customer-friendly data authorization mechanisms, such as digital consent via mobile or web-based interfaces. This would streamline onboarding and ensure faster and more reliable access to interval meter data.

D. Load factor would be a useful metric for measuring load shift progress

CEC Commissioner McAllister and Vice Chair Gunda posed the idea of utilizing load factor as a metric for measuring the success of load shifting on the grid. This is an intriguing concept that could potentially be used to inform incentive levels to drive demand flexibility resources to be deployed at optimal locations during optimal time frames. This issue would be appropriately considered within the context of a DR rulemaking at the CPUC.

Thank you for your consideration.

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[4] YouTube link to UC Davis presentation which can be found in this webinar: https://youtu.be/8a5IPcNa4HU?feature=shared.