BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance Demand Response in California.	Rulemaking 25-09-004 (Filed September 18, 2025)

OPENING COMMENTS OF THE CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL ON THE ORDER INSTITUTING RULEMAKING TO ENHANCE DEMAND RESPONSE IN CALIFORNIA

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Joseph Desmond
Executive Director
California Efficiency + Demand Management Council
849 E. Stanley Blvd #264
Livermore, CA 94550
Telephone: 925-785-2878
E-mail: policy@cedmc.org

Luke Tougas
Consultant for
California Efficiency + Demand Management Council
849 E. Stanley Blvd #264
Livermore, CA 94550
Telephone: 510-326-1931
E-mail: l.tougas@cleanenergyregresearch.com

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I. INTRODUCTION

The California Efficiency + Demand Management Council (the "Council") submits these Opening Comments on the Order Instituting Rulemaking to Enhance Demand Response in California ("OIR"), pursuant to Rule 6.2 of the Rules of Practice and Procedure of the California Public Utilities Commission ("CPUC" or "Commission") and the instructions accompanying the OIR issued September 29, 2025.

II. BACKGROUND

The Council is a statewide trade association of non-utility businesses that provide energy efficiency, demand response, and data analytics services and products in California.[1] Our member companies employ many thousands of Californians throughout the state. They include energy efficiency ("EE"), demand response ("DR"), and distributed energy resources ("DER") service providers, implementation and evaluation experts, energy service companies, engineering and architecture firms, contractors, financing experts, workforce training entities, and energy efficient product manufacturers. The Council's mission is to support appropriate EE, DR, and DER policies, programs, and technologies to create sustainable jobs, long-term economic growth, stable and reasonably priced energy infrastructures, and environmental improvement.

The Council was a party to and actively participated in the previous DR rulemakings (Rulemaking ("R.") 13-09-011 and Application ("A.") 22-05-002, et al.). The Council has been or is a party to other Commission proceedings, including, but not limited to, the EE rulemakings

[1] Additional information about the Council, including the organization's current membership, Board of Directors, antitrust guidelines and code of ethics for its members, can be found at http://www.cedmc.org. The views expressed by the Council are not necessarily those of its individual members.

(R.25-04-010, R.13-11-005, and A.22-02-005, et al.), resource adequacy ("RA") rulemakings (R.21-10-002 and R.23-10-011), the Customer DER rulemaking (R.22-11-013), and the DR proceedings (R.13-09-011 and A.22-05-002, et al.).

III. THE COUNCIL'S COMMENTS ON PRELIMINARY SCOPE OF R.25-09-004

1. What guiding principles should the Commission adopt for demand response policies?

The Council supports a refresh of the existing DR Guiding Principles and provides its comments on the proposed Guiding Principles later in these opening comments. In any context, guiding principles can be very helpful in ensuring alignment of policies and actions to achieve a better outcome. However, guiding principles are only useful if they are consistently adhered to and tied to policy development. Some DR policies adopted, or not adopted, by the Commission over the past several years have not aligned with certain existing DR Guiding Principles, especially with regard to transparency, preference for third parties, and competitive neutrality. Therefore, in the course of adopting updated DR Guiding Principles, the Commission should explicitly require a showing that all new DR-related policies are aligned with them.

2. What policies should the Commission adopt or amend to make demand response resources more consistent, predictable, reliable, and cost-effective, including but not limited to:

a. Dual participation;

The Council strongly supports including this issue in the proceeding scope. To date, the rigidity of dual participation rules has been largely due to two constraints – the location where performance is measured (i.e., at a customer meter) and the time frame during which DR is authorized to provide Resource Adequacy ("RA") capacity (i.e., the Availability Assessment Hours ("AAH"). Measuring DR participant performance at the customer's utility meter can complicate program-specific performance measurement when the customer is simultaneously enrolled in two different DR programs. For example, if multiple programs are dispatched during overlapping hours, it is very difficult to differentiate the performance of the two programs. Even if there is no overlapping dispatch, one program's dispatch can complicate the performance measurement for the other program by eliminating the event day as a useful day for baseline calculation.

A great deal of change has occurred in the DR market that necessitates a reconsideration of the existing dual participation rules. One of the primary factors driving the need for this

reconsideration is the adoption of the Slice of Day ("SoD") RA framework which currently enables all capacity resource types other than DR to provide RA during any hourly slice during which they are available. If DR is ultimately allowed to provide RA outside of the AAH, it is entirely possible that some customers will participate in multiple DR programs. In addition, the proliferation of a wide range of technologies, including behind-the-meter ("BTM") electric and thermal storage, and smart technologies such as thermostats, heat-pump water heaters, and electric vehicle supply equipment ("EVSE"), creates opportunities for the owners of these technologies to deliver RA at the optimal time of day for each technology based on each participant's load patterns.

Additionally, there has been a growing trend whereby technology providers also act as DR providers for their customers but prefer to avoid working with the other enabling technologies that their customers may have. This has the effect of "stranding" some enabling technologies because DR participants are prohibited from enrolling with multiple DR providers. If a customer enrolls through one DR provider that only controls a single device that the customer owns, that customer's other devices will sit fallow in their homes, unable to be leveraged by other DR providers because existing regulations require customers to register in DR programs at the meter level rather than at the device level.

For all of these reasons, the Commission must develop a framework designed for customers with multiple smart technologies to participate in separate DR programs and/or with separate DR providers, during any time of day that load curtailment can be delivered. This would enable every DR participant to maximize the potential of their load curtailment by utilizing all enabling technologies at their disposal. The Council recognizes that similar dual participation restrictions exist in the California Independent System Operator's wholesale electricity market, but the Commission must lead the way as the jurisdictional local regulatory authority.

b. Valuation methodologies and evaluation metrics;

The Council supports this category of issues in the scope of this proceeding. One of the important barriers that needs to be addressed is measuring performance by frequently-dispatched resources (and potentially by multiple DR programs enrolled in by the same participant) due to the difficulty in finding an adequate number of "like" days for the purpose of calculating 5-in-10 and 10-in-10 baselines. Control groups, i.e., matched comparison groups, which have already

been approved by the Commission and the California Independent System Operator ("CAISO") in concept, can address this problem because they compare a dispatched customer's load to that of similar non-participating customers. However, utilizing control groups are infeasible on a practical level for third-party DR providers because they do not have the luxury of withholding large quantities of participants for this purpose, and they do not have access to non-participant meter data. To address this accessibility problem, this proceeding should consider how to create control groups for representative customer segments, climates, and enabling technologies that can be utilized by the investor-owned utilities ("IOUs") and third-party providers. In addition to improving the accuracy of performance measurement in general, it would create a uniform set of baselines against which IOUs and DR providers alike could measure their performance.

Another issue that should be addressed in this category is a program framework for load-shift resources. Though dynamic rates are intended to motivate load shifting, this should not preclude the development of load shift DR programs (either as tariffed DR programs or bilateral contracts) which can be stood up more quickly than large scale customer enrollment in dynamic rates. This framework should include cost-effectiveness and performance measurement methodologies.

This proceeding should also adopt meter accuracy standards for enabling technologies, especially thermal and electric energy storage, and smart thermostats. These technologies tend to come with their own performance measurement mechanisms as a standard feature, whether they measure actual time-dependent electricity (or equivalent) output or, in the case of some smart thermostats, run times. As a corollary to this issue, a standardized format for the data should also be adopted to ensure that the data can be used by IOUs, the CAISO, and other entities as necessary. This issue is particularly important, especially for energy storage, because for purposes of CAISO market settlement, Commission-defined meter accuracy standards supersede the CAISO's default meter standard. The Commission has already adopted all of these rules for sub-metered EVSE in Decision ("D.") 22-08-024 so it would not be necessary to develop an entirely new set of rules; instead, D.22-08-024 could serve as a starting point for a proposal that could be tailored to electric and thermal energy storage at the very least due to their similarity to EVSEs.

c. CAISO market integration topics

It is critical to have good coordination between the Commission and the CAISO where both entities have jurisdiction over certain pieces of related issues, including DR. This is especially timely in light of the ongoing work of the CAISO's Demand and Distributed Energy Market Integration ("DDEMI") stakeholder initiative which is poised to begin consideration of issue papers for specific market proposals, some of which may require modification of Commission-jurisdictional DR rules to mirror changes to related CAISO rules. As the CAISO proposals are rolled out and approved by its Board of Governors, it will be necessary to identify any Commission-jurisdictional issues that will need to be addressed for these initiatives to be implemented once approved by the Federal Energy Regulatory Commission ("FERC"). According to the *CAISO's 2026-2028 Draft California ISO Policy Initiatives Roadmap*, they anticipate the initial round of proposal development to occur in Q1-Q2 2026 followed by a decision (the Council presumes this refers to the Board of Governors and the FERC) in Q3.[2] To the extent that any CAISO DDEMI proposals require coordination with the Commission, to avoid implementation delays, the Council respectfully recommends that the Energy Division DR Section coordinate with the CAISO to identify these dependencies and modify the DR rulemaking scope accordingly. It is the Council's understanding that CAISO staff will be monitoring developments in the DR rulemaking as well.

d. Resource adequacy valuation and slice-of-day implementation;

This category is critical to the success of this proceeding because there are many issues to be addressed that have been accumulating over the past several years while consideration of DR-specific RA issues have been limited to the RA proceeding only. Some of these needed changes have been driven by the adoption of the SoD regime, but most are necessary to address longstanding barriers and distortions to the DR market. These issues are explained below.

There should be a clear and transparent process by which the Energy Division assesses IOU and DR providers' annual Load Impact Reports. In April of each year, IOUs and those third-party DR providers that want to sell RA capacity submit a Load Impact Report which contains ex post analysis of their prior year's portfolio performance as well as ex ante analysis for the upcoming year. The Energy Division, often supported by CEC staff, reviews the

[2] The Draft Roadmap can be found here: https://stakeholdercenter.caiso.com/InitiativeDocuments/Draft-2026-2028-Policy-Initiatives-Roadmap.xlsx

Load Impact Reports and makes a final determination of each IOU's and DR provider's Qualifying Capacity ("QC") values. In the past few years, many DR providers' QC values have been far lower, sometimes 50 percent or more, than what was forecasted in their Load Impact Reports. In contradiction with the DR principle that "Demand response processes shall be transparent," the Energy Division's review process is unknown and no explanations are given to DR providers for such heavy derates. Consequently, DR providers are given no opportunity to address, in a practical way, the shortcomings that Energy Division presumably finds in their analyses. For any market to function efficiently, it is critical to have transparency and accountability. The current QC assessment process provides neither. In this proceeding, a clear, well-documented, and transparent process, which could include a standardized software tool, for assessing QC values must be developed, as well as a process to ensure that the adopted process is maintained. Preserving the current dysfunctional and arbitrary RA valuation process risks discouraging DR provider participation in the RA market at a time when RA capacity continues to be desperately needed.

The Commission should adopt a QC counting framework for exporting BTM energy storage. Currently, the RA value of DR participants can only be based on their load curtailment to a "zero" value at the customer meter (i.e., up to the point that their load curtailment equals their onsite load). However, there is a substantial amount of exporting (i.e., subject to Electric Rule 21 requirements) BTM energy storage online, sometimes paired with a PV system, with more expected in the future, which could be used to provide additional DR capacity if the current RA counting rules could be modified to include these exports. The Commission's own policies through its revisions to the net energy metering compensation structure incentivize customers to adopt solar plus storage ("SPS") rather than BTM solar only, so the Commission should take the next logical step to leverage the extra capacity value of BTM energy storage and SPS to improve system reliability and reduce ratepayer costs. The absence of such a framework has stranded close to 1 GW of valuable capacity so far, and will strand significantly more in the future as the number of BTM batteries grow in number and size. Parties have submitted counting proposals in the RA proceeding in the past - the most recent one

that was submitted by the Joint DER Parties in R.21-10-002 was ultimately rejected but it can serve as a good starting point.[3]

DR should be expanded to providing RA outside of AAH. The SoD framework made significant changes to the RA compliance regime – from procuring sufficient resources to meet the peak hour load of the peak day (plus Planning Reserve Margin) to meeting each hour of the "worst" day of each month. Consequently, the SoD regime requires load-serving entities ("LSEs") to procure resources to meet a discrete RA requirement for each hour of the day, i.e., 24 hourly slices. To meet these hourly RA requirements, with the exception of DR, most RA resources are allowed to sell their hourly capacity during any hour of the day they are capable of delivering energy. However, all DR resources continue to be limited to providing RA solely during the AAHs. This continued restraint of DR overlooks the importance of allowing all RA resources to deliver capacity when they are capable of delivering it and when it is needed most. This also overlooks the fact that curtailable load exists outside of the AAH, depending on the type of load being curtailed. For example, some non-residential customers may have high process loads during the morning hours that can be curtailed. A more common example may be participants with BTM energy storage, who will have the flexibility to dispatch their storage when it provides the greatest incremental benefits to the grid. Therefore, limiting DR to the AAH does not reflect its actual capabilities.

Shorter DR dispatches must be allowed. The rulemaking should consider reducing the minimum dispatch requirement for DR resources from four hours to two-hours. Currently, a RA resource must be capable of dispatching for four consecutive hours on three consecutive days. This four-hour dispatch capability was logical based on the "peak hour of the peak day" approach of the prior RA regime because it ensured, in theory, that DR resources would be available to dispatch during the time prior to, and after, the peak hour. However, because the SoD framework is solving for every hour, it is less important that every DR resource have a four-hour capability than for them to be able to target dispatch during the hour-long slices for which they have been contracted to provide RA. Additionally, though some types of curtailable load can maintain a relatively consistent dispatch level throughout a four-hour window, the reality is that some types cannot. In these latter instances, this has the effect of diminishing their QC

[3] Joint DER Parties Implementation Track – Phase 2 Proposal, submitted in R.21-10-002 (RA) on January 21, 2022.

value because it is calculated over a four-hour dispatch period. The most prominent example of this is cooling load. There is significant evidence available demonstrating that curtailed cooling load tends to restore to its pre-event levels after two hours. Requiring that these resources to dispatch for four hours significantly reduces the amount of RA they can provide, and often require DR providers to stagger their participants' two-hour curtailments over a four-hour dispatch period rather than focus them on the shorter "super peak" periods where they are most valuable.

Review the current DR testing requirements and the rule allowing Energy Division to unilaterally derate a DR portfolio based on a single test event. In D.20-06-031, the Commission adopted minimum testing requirements for third-party DR resources procured by non-IOU LSEs. These testing requirements consisted of a two-tiered approach in which "new or changing" DR resources would be subject to one four-hour dispatch (either as an economic dispatch or out-of-market test event) per quarter, whereas "stable resources with solid track records" would only require one two-hour test per year. In adopting this two-tiered testing requirement, the Commission cited an insufficient record to determine criteria to differentiate between "new and changing" resources and "stable" resources, and directed that all third-party DR resources procured by non-IOU LSEs would be subject to the stricter testing regime pending the development of a clear set of rules.[4] These rules have yet to be developed. The preliminary scope should be modified to include 1) the development of criteria for defining new and changing resources versus stable resources, 2) design of a less stringent testing requirement, and 3) the process through which third-party DR resources can test out of the four-hour quarterly testing requirements to the less stringent testing requirement.

This rulemaking should address the discrepancy in DR bidding obligations between IOUs and third-party DR providers. Currently, IOU DR programs are informally treated as variable energy resources ("VER") in that they are not shown on supply plans nor are they required to bid their QC value in the CAISO market. Instead, they are allowed to bid based on their day-to-day capabilities regardless of their QC values. Conversely, third-party DR resources are subject to much stricter rules governing their bidding requirements in the CAISO market – they must be shown on supply plans and are subject to a Must-Offer Obligation ("MOO") in the CAISO market which is equal to their QC value. This can be seen in the CAISO Department of

[4] D.20-06-031, at p. 40.

Market Monitoring's *Demand Response Issues and Performance 2024* report which shows that IOU Proxy Demand Resource ("PDR") DR is bid far below its credited RA value compared to third-party PDR DR (The Council has omitted IOU Reliability Demand Response Resources in order to have an "apples to apples" comparison).

Figure 2.4 Utility proxy demand response availability and resource adequacy credits

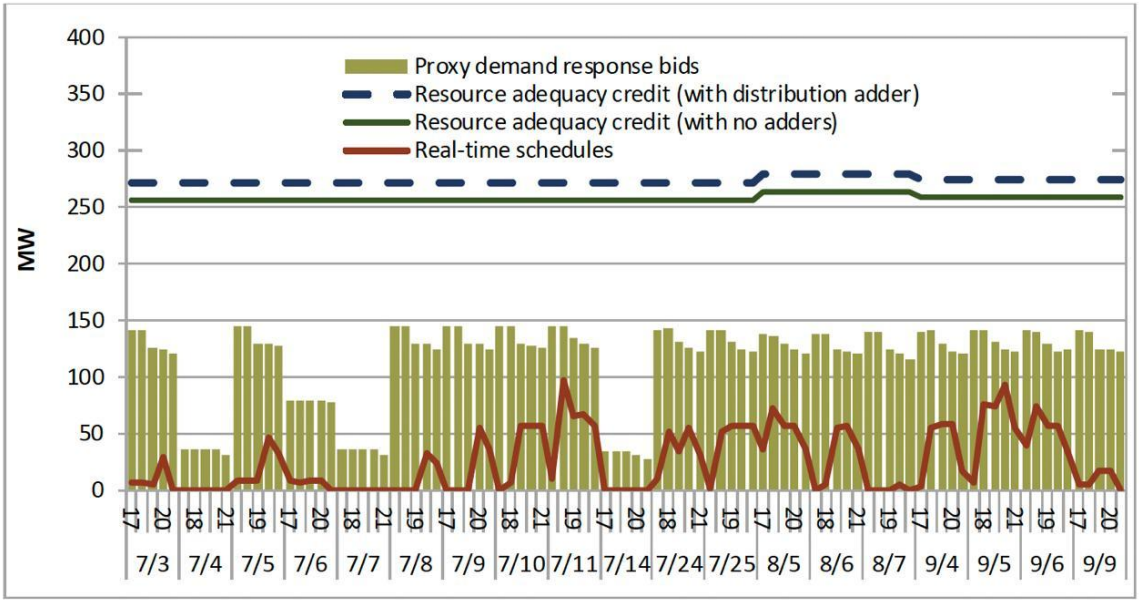


Figure 2.5 Day-ahead and real-time availability of supply plan demand response

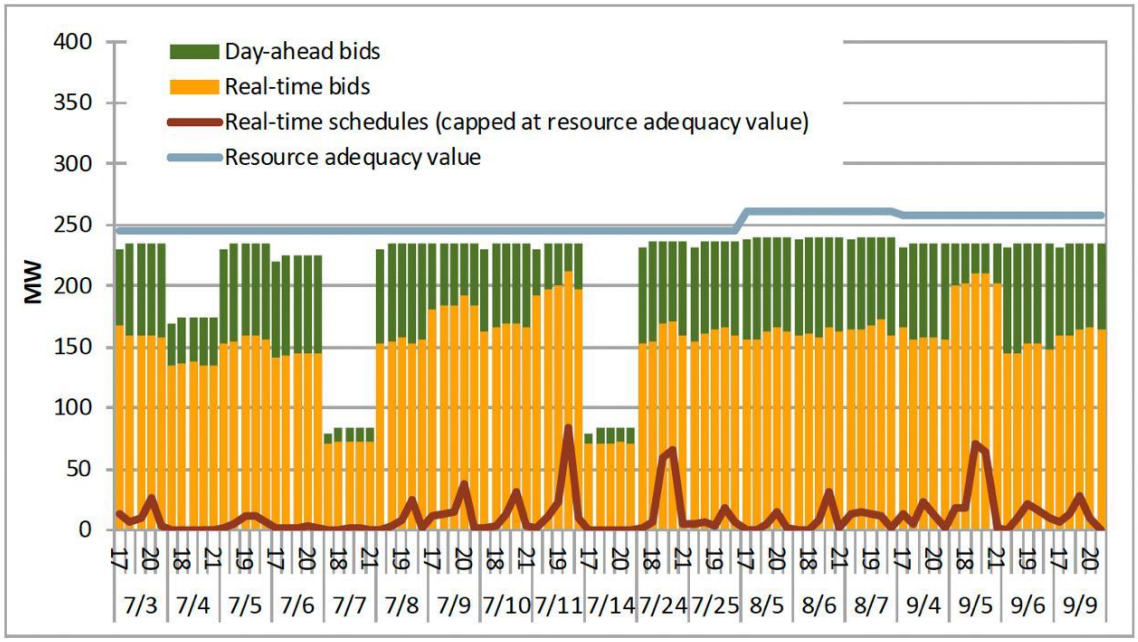


Figure 2.10 CPUC-jurisdictional utility proxy demand response performance

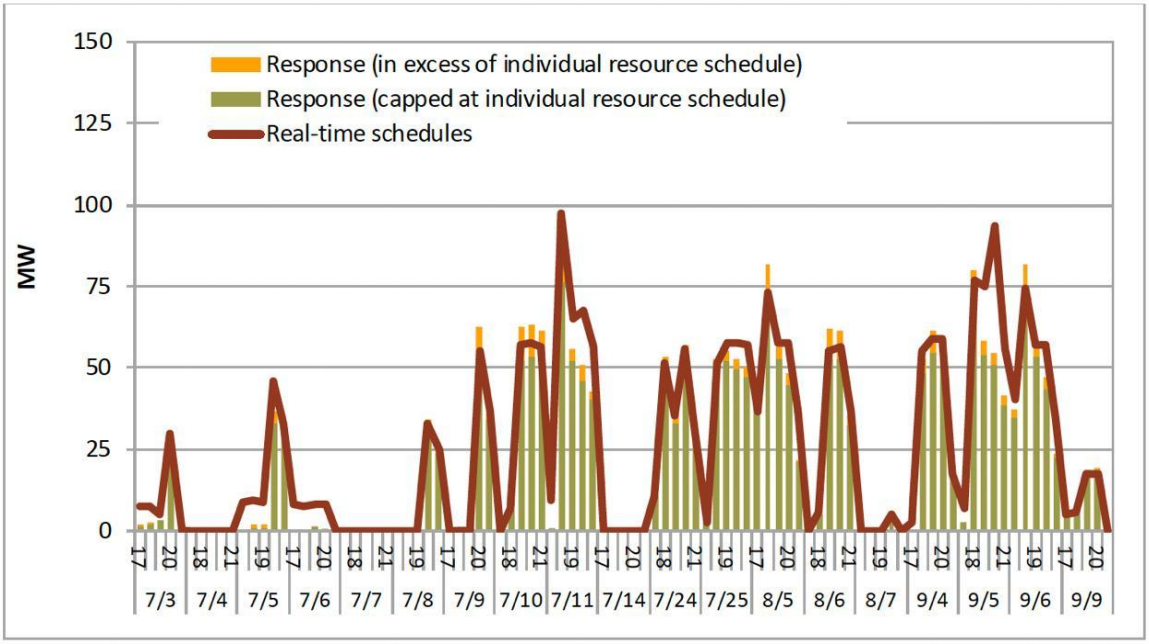
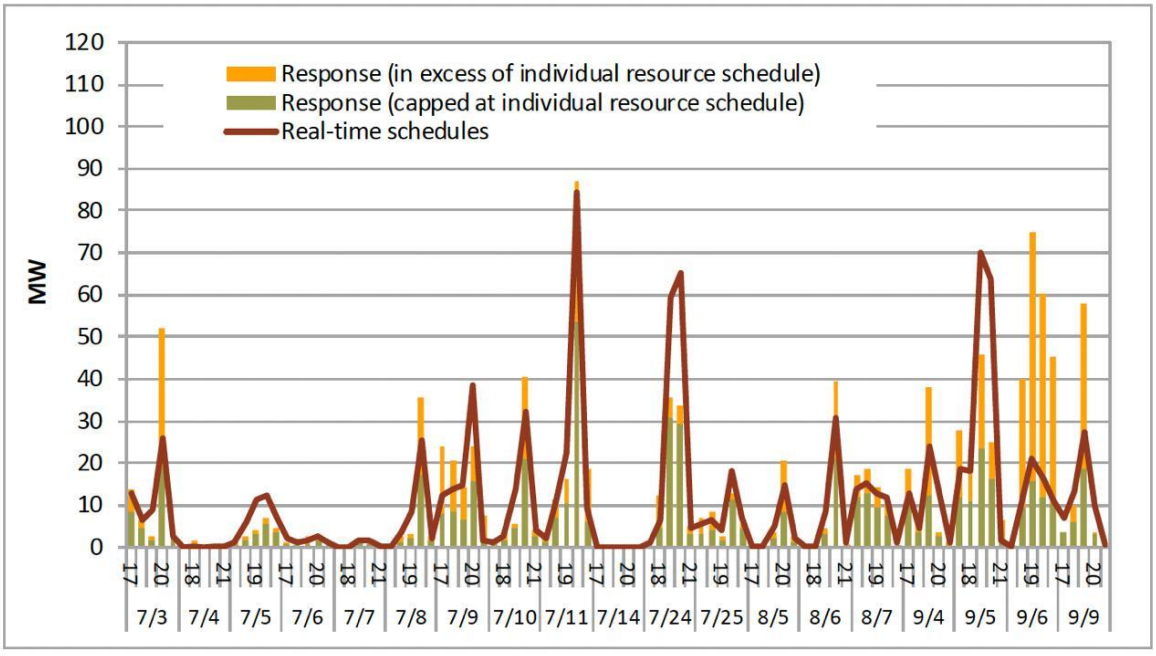


Figure 2.12 Supply plan demand response performance



When an IOU DR resource is able to bid according to its capability on a given day, then when it is scheduled in the market, it is more apt to meet its schedule than it would if it was scheduled based on its QC value. Using an example, an IOU DR resource with 5 MW of QC value may bid only 3 MW should the IOU calculate that this is the maximum that the resource

can provide on a given day. If the DR resource was scheduled for 3 MW and it delivered the scheduled amount, then its performance would be 100 percent. However, a DR provider with the exact same 5 MW DR resource would be required to bid the full 5 MW even if, like the IOU's resource, the capability of the DR provider's resource for that day was 3 MW. If the 5 MW was scheduled and only 3 MW was delivered, then its performance would be 60 percent. In this example, the IOU delivered the same amount of energy as the DR provider but would be credited with 100 percent performance while the DR provider performance would be 60 percent. This discrepancy in treatment is highly uncompetitive and discriminatory, and has created a false narrative that third-party DR is less reliable than IOU DR. As a consequence of this false narrative, third-party DR has been subjected to more rigorous rules than IOU DR programs. Most prominent among them are the bifurcated testing rules adopted in D.20-06-031 and the Energy Division authorization to impose an intra-year derate of a DR provider's portfolio based on a single test event.

3. **What standardized data systems, communication protocols, and data transfer processes should the Commission adopt or amend to support demand response initiatives, including dynamic rates?**

Twelve years after the Commission issued D.13-09-025, *Decision Authorizing Provision of Customer Energy Data to Third Parties Upon Customer Request*, Customer Data Access ("CDA") continues to be a major barrier to third-party DR providers enrolling customers and managing their participation in the CAISO market. The customer authorization process (often referred to as the "Click-Through Process" ("CTP")) to share meter data with DR providers is unreliable to the point that a majority of customers fail to complete it.[5] Also, the quality and timeliness of these data are sometimes inadequate which creates a poor customer experience and inhibits the efforts of DR providers to improve performance. Though these shortcomings have so far been confined to DR providers so far, if the Commission remains committed to the large-scale rollout of dynamic rates, they will likely be experienced by the participating automation service providers ("ASP").

With this context, this rulemaking should address the challenges being experienced by DR providers and would-be participants as dynamic rates are rolled out at a larger scale. To avoid yet another round of working groups, the most efficient approach would be to adopt CDA

[5] 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.

principles and performance standards that are grounded in industry best practices to ensure that each IOU provides a consistently high quality of service. These principles and performance standards could then inform additional investments that the IOUs would need to make that they could request through subsequent applications. As a starting point, the Commission should refer to the presentation provided by UtilityAPI at the January 17, 2024 CEC workshop on Load Management Standards Implementation.[6] In that presentation, UtilityAPI cited the following barriers:[7]

1. Inconsistent implementation of the Green Button Connect standards by the IOUs
2. Lack of accountability for the Green Button Connect platforms
3. Low ongoing awareness of issues amongst staff at utilities, CPUC, CEC
4. Split incentives between customers, solution providers, utilities, and the state
5. Jurisdictional ambiguity between utility, state, market, and federal

To address these barriers, UtilityAPI recommended a series of data access principles that can act as guidelines to help assess the improvements needed to the current CDA ecosystem.[8] The Council provides its own commentary on each proposed principle:

1. Security, ease of use, and consistency are paramount: Data security is of course paramount to any system in which customer data are shared between LSEs and third parties. However, this does not need to come at the expense of ease-of-use by the customer and the third parties that have been authorized by each customer to handle their data. Also, as addressed further below, consistency in performance standards across LSEs' Green Button Connect ("GBC") platforms is critical to ensure an equal opportunity for all customers to participate in programs. In addition, because third parties serve customers across multiple LSEs, consistent standards are needed to avoid unnecessary business costs that occur from having to manage different LSE processes and standards.
2. Customer sign-up (and disenrollment) should be simple, fast, automated: This principle is foundational to the ability of third parties to enroll customers in their DR programs, including future dynamic rate programs, as well as the success of the LMS, LSG, and

[6] January 17, 2024 UtilityAPI presentation, 23-LMS-01, https://efiling.energy.ca.gov/GetDocument.aspx?tn=253913&DocumentContentId=89215.
[7] *Id.*, at slide 8.
[8] *Id.*, at slide 16.

CalFUSE. The Council would also stress that the speed of enrollment and disenrollment should be balanced with the need to ensure customers understand the implications of their decisions.

3. Data authorization process should meet technology industry standards, not individual utility standards: Presently, and despite the click-through solutions' clear classification as an IT system, neither the IOUs nor the Commission has defined service-level expectations, including expectation of uptime, availability, and accuracy. However, the industry standard for IT service providers is 99.8% or above for these three factors. Only when the IOUs are held to a standard consistent with other IT providers will the CTP function at the necessary level.
4. Data (settlement, forecasting, rates, bills, usage) must be timely and accurate: This principle is also foundational to successful deployment of DERs, including DR, behind-the-meter resources, and dynamic rates. UtilityAPI made an excellent point that as time goes on, more and more businesses will enter this market and will be wholly reliant on the functionality of the GBC platforms. As a result, when data access goes down, these businesses will shut down. For small businesses with only a small margin of error between surviving and staying open, data outages can be catastrophic. Third parties must be provided accurate and complete customer meter data on a timely basis in order to ensure that, as UtilityAPI put it, the LMS is truly reliant on a well-functioning ecosystem of integration based on open standards that can be certified, enforced, and also provide seamless access to just general customer utility data. (emphasis added) The system that the CEC and CPUC are building, which envisions more customer segments participating in third-party programs than ever before, will surely fail if this issue cannot be fixed.
5. Consolidating integration point and methods are critical to driving scale: In addition to these principles, UtilityAPI also recommended requiring certified GBC platforms for IOUs, POUs, and CCAs that can be integrated with MIDAS and support statewide initiatives. Creating a GBC certification regime would require consistent standards and provide a necessary target to eliminate any ambiguity among each LSE for acceptable performance. This recommendation also highlights the implications for MIDAS if IOUs are unable to rectify current problems by providing timely and accurate customer data. The Council acknowledges that IOUs must maintain specific customer utility data

functions for operational reasons; however, given the significant time and investment likely needed by IOUs to meet a higher data quality standard, certain economies of scale with a higher level of quality may be realized by the CEC taking on certain functions (e.g., meter data quality assurance), and this should be seriously considered.

The aforementioned barriers and principles culminate in UtilityAPI's final recommendation to establish performance standards on which all platforms must be held accountable. These requirements would apply to both the customer data access and customer sign-up/disenrollment, and would be based on the following metrics:[9]

1. Accuracy
2. Timeliness
3. Completeness
4. User experience
5. Errors/outages
6. Support
7. Onboarding

The Council strongly recommends that this rulemaking should adopt performance standards using these seven metrics that all IOUs would be required to meet. As a related issue, this rulemaking should consider whether a more centralized customer data system like Smart Meter Texas would be a more reliable and cost-effective platform than individual IOU systems.

IV. THE COUNCIL'S RECOMMENDATIONS FOR ADDITIONAL ISSUES OR DETAILS THAT SHOULD BE INCLUDED IN THE SCOPE OF THIS PROCEEDING

The OIR invites parties to comment on whether there are additional issues or details that should be included in the scope of this proceeding.[10] In its comments above, the Council has provided specific topics for consideration within each of the preliminary scope categories. However, there remain some recommended topics for which there is no clear category. These are:

Equal access to technology incentives: Customers enrolled with third-party DR providers are ineligible to receive technology incentives through the Automated Demand

[9] January 17, 2024 UtilityAPI presentation, 23-LMS-01, https://efiling.energy.ca.gov/GetDocument.aspx?tn=253913&DocumentContentId=89215. at slide 17.
[10] OIR, at p. 10.

Response ("AutoDR") program and the statewide Self-Generation Incentive Program ("SGIP"), even if they provide RA capacity. This practice is arbitrary and discriminatory, and violates the DR principles that "Demand response customers shall have the right to provide demand response through a service provider of their choice and Utilities shall support their choice by eliminating barriers to data access" and "Demand response shall be market-driven leading to a competitive, technology-neutral, open market in California with a preference for services provided by third-parties through performance-based contracts at competitively determined prices, and dispatched pursuant to wholesale or distribution market instructions, superseded only for emergency grid conditions."

In this context, the preferential treatment given to IOUs skews customer preferences toward their programs by demotivating participation with DR providers. Put simply, if a customer can only qualify for a technology incentive by enrolling in an IOU DR program, then all else being equal, they will do so rather than enrolling with the DR provider.

V. THE COUNCIL'S RECOMMENDATIONS FOR SPECIFIC ISSUES THAT REQUIRE COORDINATION

The OIR invites parties to comment on whether there are any specific issues previously addressed or underway in other Commission proceedings that require coordination with this rulemaking.[11]

VI. THE COUNCIL'S RECOMMENDATIONS FOR THE GUIDING PRINCIPLES

The OIR invites parties to comment on whether the proposed Guiding Principles should be adopted or if any modifications are needed.[12] The Council provides feedback on the Energy Division's proposed principles and offers its own proposed principles as well.

Proposed Principles:

> 1. Demand response shall be **predictable and reliable** in order to be incorporated into the State's forecasting and planning frameworks and be depended on in both system planning and real-time grid operations.[13]

The Council opposes this proposed principle because it creates the risk that DR will be held to a higher standard than other resources, and leaves open the fundamental question of what constitutes a sufficient degree of predictability and reliability. The reality is that customer load is

[11] OIR, at p. 10.
[12] *Id*.
[13] Guiding Principles, at p. 1.

variable so the amount of load curtailment each customer can provide is, in turn, variable as well. In fact, the Commission recognized this when it declared DR as a Variable Energy Resource stating, "DR is a variable resource with behavioral and weather-dependent characteristics and DR should be treated as such in CAISO's markets."[14] It would be unrealistic for the Commission to expect DR to function as predictably and precisely as a conventional generator which, in the absence of a definition of "predictable and reliable", leaves the door open for any subjective interpretation that suits the needs of the Commission. Furthermore, uncertainty in the supply of any resource, not only DR, can exist and still be incorporated into the State's forecasting and planning frameworks.

In the Integrated Energy Policy Report process, the California Energy Commission ("CEC") performs extensive forecasting of resources such as BTM photovoltaic capacity, electric vehicles, energy efficiency, and other factors that inform the load forecast that culminates in RA requirements in the Commission's RA proceeding. To the Council's knowledge, none of these resources roles in system planning are being diminished due to their uncertainty. Even on the supply side, a perfect forecast of available resources cannot be created because there are too many variables that impact development of new resources. This has been most recently observed over the past few years in which new and expanded generation projects being built to meet the long-term procurement approved in the Integrated Resource Plan proceeding have been delayed due to supply chain issues, cost and availability of financing, etc.

The Council also strongly disagrees with the element of this proposed principle that DR must be "depended on…in real-time grid operations." This is a loaded statement that could easily be interpreted to eliminate DR as a long-start resource. Fundamentally, DR relies on the physical ability of participating customers to curtail their load for an event. Some customers are able to respond faster than others but all DR has value and should not be thrown away simply because it cannot be dispatched (or re-dispatched) in real-time.

> 2. **Standard and consistent** valuation methodologies and evaluation metrics, along with standardized data formats, communication protocols, and data access processes, shall be adopted to enhance the transparency, comparability, and effectiveness of demand response resources and programs across the State.[15]

[14] D.21-06-029, Finding of Fact 5.
[15] Guiding Principles, at p. 1.

The Council supports this principle if it includes a requirement of transparency in the valuation methodologies and evaluation metrics. Without transparency, there is no opportunity to improve performance and there is no accountability in the application of valuation methodologies and evaluation metrics. Furthermore, consistency in evaluation must be based on equitable treatment of IOU and third-party DR, including equal access to customer meter data, equal testing requirements, equal access to technology incentives, and equal RA performance requirements. The Council recommends the following edit:

> **Standard, ~~and~~ consistent, and transparent** valuation methodologies and evaluation metrics, along with standardized data formats, communication protocols, and data access processes, shall be adopted to enhance the transparency, comparability, and effectiveness of demand response resources and programs across the State.

The third guiding principle is as follows:

> 3. Demand response resources in California shall be **cost-effective** and demonstrate clear value by delivering measurable system and ratepayer benefits.[16]

The Council supports this principle because DR programs should deliver equal or more value to ratepayers than what they pay for it. However, there should be a recognition that third-party DR RA contracts are cost-effective just as any other RA contract, by way of being procured in a competitive market. The Council recommends the following edit:

> Demand response resources in California shall ~~**be**~~ **meet** cost-effective**ness requirements or be procured in a competitive market,** and demonstrate clear value by delivering measurable system and ratepayer benefits.

The fourth guiding principle is as follows:

> 4. Demand response resources and programs shall continue to support California's **energy and environmental goals** and prohibit use of fossil fuel generation except under strictly limited conditions.[17]

The Council supports this principle.

In addition, the Council proposes the following new guiding principles:

New: Rules governing DR must be identical in form and application for IOU-administered and third-party DR, including testing regimes, derates, bid obligations, and performance scoring, to prevent structural bias in resource accreditation.

[16] Guiding Principles, at p. 1.
[17] *Id*.

New: Supply Resource and Load Modifying DR are equally valuable in supporting reliability.

With regard to the latter proposed guiding principle, both Supply Resource and Load Modifying DR should be appropriately valued in their ability to support reliability and reduce peak demand. This must necessarily include resources – including IOU DR programs – that are unable to integrate into the CAISO market, but nonetheless drive measurable load curtailment during peak periods. In addition to facilitating the development of DR portfolios incorporating a range of both Supply Resource and Load Modifying DR resources, the Commission should further maximize load reduction potential by enabling participation in DR programs across customer segments, including residential, commercial, and industrial.

VII. THE COUNCIL'S COMMENTS ON CATEGORY, NEED FOR HEARING, AND SCHEDULE

As the Council has demonstrated above, there are many issues that must be addressed in this proceeding. Given the limited time available, there should be at least two overlapping tracks. Track 1 should begin immediately and address DR Principles, then move on to Data Systems and Processes, then dual participation. Track 2 should begin in late Q1 2026 and initially address Resource Adequacy issues then any additional issues that are added to the proceeding scope. The Council also respectfully recommends that the Commission account for the fact that the IOUs will be submitting their next DR program applications on November 1, 2026.

VIII. CONFIRMATION OF PARTY STATUS

Pursuant to Section 9 at page 13: "Persons may become a party pursuant to Rule 1.4, including filing comments in response to the OIR." By filing these responsive comments, therefore, the Council requests "party status" and inclusion on the service list of R.25-09-004 as a party as follows:

Joseph Desmond
Executive Director
California Efficiency + Demand
Management Council
849 E. Stanley Blvd #264
Livermore, CA 94550
Telephone: 925-785-2878
E-mail: policy@cedmc.org
FOR: THE CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL

IX. CONCLUSION

The Council appreciates the Commission's consideration and the opportunity to provide Opening Comments on the OIR. The Council urges the Commission to amend the preliminary scope for this OIR as recommended herein.

Dated: November 13, 2025

Respectfully submitted,

/s/ JOSEPH DESMOND

Joseph Desmond
Executive Director
California Efficiency + Demand Management Council
849 E. Stanley Blvd #264
Livermore, CA 94550
Telephone: 925-785-2878
E-mail: policy@cedmc.org