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Demand and Distributed Energy Market Integration: Track 1 Draft Final Proposal

End-Use Customer Exports in Demand Response Performance Measurement

July 8, 2026

Table of Contents

Executive Summary

The California Independent System Operator (ISO) is advancing Track 1 of its Demand and Distributed Energy Market Integration (DDEMI) initiative with targeted changes to how demand response (DR) performance is measured and settled. As more customers install behind-the-meter batteries and other distributed energy resources, these changes are intended to provide greater flexibility for participation in wholesale DR programs while maintaining operational reliability and market safeguards. Based on stakeholder feedback, the draft final proposal continues to allow individual customers within a DR aggregation to export electricity to the grid if they have permission from their utility. However, the aggregation as a whole may not be a net exporter.[1]

This approach enables greater use of behind-the-meter resources while not modifying the fundamental definition of DR as load curtailment. By maintaining the existing resource-level export limitation, the proposal avoids broader West-wide market design considerations associated with representing geographically distributed exports from demand response aggregations, while separately preserving existing ISO balancing authority area (BAA) transmission planning and deliverability frameworks. Although the proposal applies broadly to market participants across all BAAs participating in ISO markets, the transmission deliverability and Resource Adequacy (RA) considerations discussed in this proposal are specific to the ISO BAA; other BAAs apply their own planning and interconnection requirements.

The changes apply to both ISO DR market models—proxy demand response (PDR) and reliability demand response resources (RDRR)—which are available to all market participants. Today, these models are primarily used in the ISO's BAA, but could become more valuable elsewhere as large energy users increasingly offset grid demand with local resources they own or contract, such as batteries and small generators.

Consistent with stakeholder feedback, the draft final proposal also provides greater policy clarity and implementation detail in several key areas. These include ensuring accurate settlement calculations, clearly defining implementation responsibilities, and addressing concerns regarding the interaction between wholesale market compensation and retail utility programs.

[1] Note that "export" for behind-the-meter and distributed resources refers to the ability to inject energy beyond the customer meter (in excess of co-located demand). It should not be confused for interchange transactions.

Background

In March 2026, the ISO began the policy development phase of the DDEMI initiative following a 2025 stakeholder working group process. The Track 1 straw proposal was focused on settlement rules for DR resources in ISO markets. The ISO proposed removing the requirement that SCs set customer-load meter data to zero during export intervals, while introducing a resource level export limit. This proposal would only be available for utility retail customers that are already approved for export onto the distribution system. This approach keeps DR categorized as load curtailment, minimizes unintended grid impacts if there were to be export, coordinates with the distribution utility, and ensures other resources retain their deliverability.

This proposal was driven by the following DDEMI working group-developed problem statement:

> "While PDR is the most compatible CAISO model for behind-the-meter interconnected storage, because it is conceptualized as load curtailment, it does not include any measured export of energy from individual locations to measure performance of the resource via any of the existing PEMs—including metering generator output methodology—so that behind-the-meter storage aggregations cannot offer the full resource capability, and PDR performance is artificially capped at levels reflecting conservative estimates of site load, resulting in significant energy from behind-the-meter storage that is unused during events and unavailable to the CAISO market."

This problem highlights a structural mismatch between behind-the-meter resource capabilities and the current DR measurement framework, which Track 1 seeks to address without redefining the ISO's demand response participation models.

ISO staff responded as a part of the final discussion paper with several comments related to market policy solutions that could be developed to address this problem, federal regulatory considerations, and a preliminary estimation of the difficulty of implementation of potential solutions. The ISO assessment for the behind-the-meter storage accounting problem statement is below:

- **Policy**: For an energy market solution to this problem, the reforms could be straightforward. Determining deliverability under a reformed PDR model that addresses this problem may require additional analysis and policy development efforts

- **Regulatory**: This highlights a “problem” that may be out of scope of the demand response/load curtailment model, but with certain considerations, could be scoped appropriately
- **Implementation**: For energy market solution, relatively low implementation difficulty

Policy Objectives

The Track 1 proposal is guided by a set of principles developed through the DDEMI working group. These principles were developed with the stakeholder community to ensure that reforms expand participation by distributed energy resources (DERs) while preserving the operational, reliability, and market design foundations of the ISO-administered markets.

Below, the ISO explains how this proposal aligns with specific principles from the DDEMI working group.

Competition

The ISO seeks to remove unnecessary barriers to participation while ensuring resources providing comparable wholesale services are subject to comparable market requirements.

This proposal enables demand response resources to more accurately reflect the capabilities of behind-the-meter (BTM) storage and other DERs already interconnected to the distribution system and authorized for export. At the same time, the proposal preserves the distinction between wholesale demand response and wholesale generation. Demand response resources continue to participate as load curtailment resources, while resources seeking to provide net generation beyond their own load remain subject to the existing generator interconnection and deliverability framework.

This approach expands participation without creating alternative pathways that would bypass requirements applicable to other wholesale resources providing similar services.

Reliability/Compliance

Wholesale market reforms must preserve the operational, market, and planning assumptions relied upon by the ISO and participating balancing authorities.

This proposal maintains the existing demand response aggregation construct by limiting exports beyond the resource level, thereby avoiding the need for fundamental changes to Full Network Model (FNM) representation, congestion management, dispatch, settlement, and other network-dependent market processes.

For the ISO BAA, the proposal also preserves existing transmission planning and deliverability assumptions by ensuring that any export capability beyond a resource's own curtailable load continues to be evaluated through established generator interconnection and transmission planning processes rather than relying on deliverability already assumed or allocated to other resources.

Efficiency

The purpose of demand response measurement is to compensate measurable and incremental wholesale services provided by wholesale resources during market dispatch.

The proposal updates settlement methodologies to better reflect actual customer operating behavior within the aggregation, including routine behind-the-meter charging and discharging patterns. Baseline methodologies continue to represent expected customer behavior, while compensation remains limited to incremental performance provided in response to ISO dispatch instructions.

Where existing baseline adjustment methodologies produce mathematically invalid or negative results due to customer export behavior, the proposal introduces targeted refinements that preserve the existing framework while maintaining settlement accuracy.

Simplicity/Feasibility

Whenever possible, the ISO seeks to evolve existing market models rather than creating entirely new participation constructs.

Rather than redefining demand response or establishing a new resource category, this proposal makes targeted modifications to existing PDR and RDRR participation models. The proposal applies consistently across existing performance evaluation methodologies, utilizes the existing Demand Response Registration System review process, and assigns implementation responsibilities consistent with existing Scheduling Coordinator obligations.

Building upon existing market structures minimizes implementation complexity while allowing near-term participation improvements.

Facilitate State Goals

Demand flexibility should be capable of supporting participation across the evolving WEIM and EDAM footprints while recognizing differences in balancing authority responsibilities.

The proposed settlement change in Track 1 applies consistently across ISO-administered markets, including participation by resources located in WEIM and EDAM BAAs. At the same time, matters related to transmission deliverability, resource adequacy treatment, and interconnection remain subject to the applicable balancing authority and regulatory jurisdiction. This approach provides a common wholesale market framework while respecting regional differences in operational and planning responsibilities.

Applying These Principles

The remainder of this proposal reflects these guiding principles through a series of targeted market rule changes that:

- Preserve demand response as a load curtailment product;
- Allow end-use customer export behavior to be accurately reflected in performance measurement where authorized by the utility distribution company;
- Maintain resource-level limits that preserve existing reliability assumptions;
- Improve settlement methodologies to accurately compensate incremental wholesale demand response; and
- Leverage existing market constructs to facilitate timely implementation.

Stakeholder Feedback: DDEMI Track 1 Revised Straw Proposal

Stakeholders generally supported the ISO's proposed incremental approach to enabling behind-the-meter and other DERs to participate in demand response while preserving the existing demand response market design. No stakeholder opposed the proposal outright, although many recommended refinements to implementation and identified topics for future stakeholder initiatives.

Areas of Broad Support

Despite differing views on future policy directions, stakeholders generally supported several core elements of the proposal. Broad support was expressed for:

- Applying the proposal across all Performance Evaluation Methodologies (PEMs);
- Limiting export recognition to customers with approved export interconnections;
- Applying the proposal to both PDR and RDRR models, with the exception of the CPUC Energy Division staff's recommendation to phase in RDRR participation at a later stage;
- Pursuing 2027 implementation, with the exception of CPUC Energy Division staff's recommendation to delay initial implementation to 2028 and to not include Net Energy Metering and Net Billing Tariff customers until double compensation concerns are resolved;
- Allowing Scheduling Coordinators to determine how resource-level export limits are applied; and
- Preserving demand response as a load-curtailment product under the existing market design.

Double Compensation

The most significant area of stakeholder feedback concerned the potential for double compensation when customers participating in wholesale demand response also receive retail compensation for exports under the CPUC jurisdictional Net Energy Metering tariffs, including the Net Billing Tariff. The three electric investor-owned utilities, CPUC Energy Division staff, and Cal Advocates expressed concern customers receive compensation through both retail and wholesale mechanisms for the same service. The CPUC Energy Division staff asserted that while the proposal may incentivize additional exports to the grid, every kWh of that export from an end-user with a Net Energy Metering and Net Billing Tariff under the proposed modification for PDR/RDRR would inherently be paid twice: 1) for energy value as exports to the grid under the administratively paid framework under Net Energy Metering and Net Billing Tariff; and 2) as wholesale energy payments. CPUC Energy Division staff recommended excluding Net Energy Metering and Net Billing Tariff customers from the proposal. The investor-owned utilities also recommended that the final proposal ensure there is not double compensation.

Other stakeholders took a different view. Tesla requested confirmation that Net Energy Metering and Net Billing Tariff customers remain eligible to participate in wholesale demand response, while CalCCA cautioned that excluding these customers could unnecessarily strand flexible capacity capable of providing reliability benefits.

See Section 7, Net Energy Metering/Net Billing Tariff Participation, for the ISO's assessment and proposed treatment of these issues.

Deliverability and Exports Beyond the Resource Level

A second area of stakeholder feedback concerned whether future DDEMI phases may enable demand response resources to export beyond the resource level, and whether modifications to the ISO BAA deliverability framework may be warranted. Advanced Energy United, CALSSA, Sunrun, Joint DR Parties (CPower and Leap), Tesla, VGIC, and Voltus supported future discussions regarding aggregation-level or sub-LAP exports and potential deliverability reforms to facilitate broader DER participation. CalCCA recommended that any changes to deliverability treatment be evaluated through a separate stakeholder effort or sensitivity analysis. In contrast, Cal Advocates, the Department of Market Monitoring (DMM), and SCE cautioned that expanded export treatment could create pathways to circumvent existing generator interconnection, deliverability, and planning requirements.

See Section 3, Export Considerations, for the ISO's discussion of resource-level export limits, Full Network Model considerations, and ISO BAA deliverability implications.

Settlement, Baselines, and Performance Measurement

Utilities and market monitoring stakeholders focused on settlement design, baseline accuracy, and performance measurement. The CPUC Energy Division staff, PG&E, and SDG&E expressed concerns that baseline adjustment methodologies may overstate demand response performance when export behavior is incorporated into baseline calculations. The Energy Division staff recommended capping adjustment factors at one, while PG&E and SDG&E requested additional refinements and examples. SCE requested standardized baseline methodologies, greater transparency into Scheduling Coordinator calculations, auditing capabilities, and draft Business Practice Manual revisions. DMM generally supported continued exploration of improved baseline approaches, including control-group methodologies, to improve measurement accuracy.

See Section 5, Settlement and Performance Measurement, and Section 6, Baselines and Performance Measurement, for the ISO's proposed settlement framework and hierarchical approach to pre-event adjustment factors.

Resource Adequacy and Non-Responsive Load

Several stakeholders raised concerns regarding the potential enrollment of non-responsive load within resource aggregations. The CPUC Energy Division staff, Cal Advocates, and SCE recommended establishing safeguards to ensure aggregations provide genuine demand response capability and are not structured primarily to absorb exports. DMM raised concerns that the enrollment of non-responsive load could result in qualifying capacity values that exceed actual resource capability and recommended coordination with local regulatory authorities. SDG&E also requested coordination with the California Energy Commission regarding potential Resource Adequacy forecasting implications. In contrast, Sunrun argued that the existing resource-level export restriction itself creates incentives to enroll non-responsive load solely to absorb exports.

See Section 3, Export Considerations—Non-Responsive Load Customers, for the ISO's response regarding aggregation composition, performance obligations, and Resource Adequacy considerations.

Future DDEMI Priorities

Many stakeholders emphasized that Track 1 should be viewed as an initial step rather than the final solution for integrating exporting DERs into ISO markets. The most common topics identified in Track 1 for future DDEMI phases included:

- Allowing aggregation-level or sub-LAP exports;
- Evaluating deliverability reforms and resource adequacy treatment;
- Modernizing device-level metering requirements;
- Simplifying customer enrollment and registration processes;

- Developing approaches for capacity accreditation of exports; and
- Improving monitoring, transparency, and customer-level data availability.

Overall, industry stakeholder comments indicate industry support for advancing Track 1 while continuing discussions on longer-term opportunities to better integrate exporting distributed energy resources into the ISO market framework, though comments from California IOUs, CPUC Energy Division staff, and Cal Advocates suggest that additional concerns must be further addressed.

Many of these topics are discussed in Section 3, Export Considerations, as potential future areas for stakeholder engagement but are outside the scope of the targeted settlement reforms proposed in Track 1.

Track 1 Draft Final Proposal

This draft final proposal provides additional specificity and clarity in key areas not fully developed in the revised straw proposal:

- Resource-level exports: market-wide vs. ISO BAA;
- Non-responsive load enrollment;
- Settlement implementation issues, specifically updates to the baseline adjustment factors; and
- Net Energy Metering and Net Billing Tariff participation.

1. Scope and Applicability

This proposal establishes a common settlement framework for demand response resources participating in ISO-administered wholesale markets. It applies to both PDR and RDRR, regardless of the PEM used.

The proposal applies across all BAAs participating in ISO-administered markets.[2] However, matters related to generator interconnection, transmission deliverability,

[2] Further enhancements necessary to fully enable these market models are being considered in DDEMI Track 2. For example, stakeholders are evaluating revisions to the tariff requirement that demand response resources be registered within a CAISO-defined sub-LAP, including potential approaches that would align location requirements more closely with the locational granularity used in WEIM and EDAM.

Resource Adequacy, and distribution interconnection remain subject to the applicable BAA, utility, or regulatory authority. Accordingly, discussions of deliverability and Resource Adequacy in this paper apply only to the ISO BAA, unless otherwise noted.

This proposal does not modify the fundamental definition of demand response. PDR and RDRR remain load curtailment products under the ISO tariff. The proposal refines how authorized customer exports are measured within those existing participation models but does not create a new resource category.

2. Resource-Level Export Framework

Definition of Demand Response

Per the ISO tariff definitions for PDR and RDRR,[3] these participation models are designed as load curtailment resources. This load curtailment resource, registered in the ISO's market models as either PDR or RDRR and assigned a wholesale resource identification number, is comprised of individual end-use customers that are aggregated together to provide the wholesale demand response service through the ISO's markets. This means that a wholesale DR resource may reduce only up to the load of the aggregated customers registered as a part of the resource. Once the aggregated customers registered as a part of a DR resource have no remaining load to curtail, the resource cannot provide additional demand response energy. This prevents the DR resource from receiving credit for amounts above the curtailable load of the aggregation, consistent with demand response rules and models. Unlike resources registered under the ISO's Distributed Energy Resource Aggregations (DERA) model, DR resources are not designed to function directly as generation resources.

If an entity wishes to participate as a generating resource (*i.e.,* provide net positive output to the grid under a market resource ID) there is a well-established process for doing so. The entity must enter the appropriate generation interconnection queue, either as a DERA or as another generator type. For distribution interconnections, this could be a wholesale distribution access tariff interconnection. For transmission interconnections, the interconnection process for the ISO or another BAA within the ISO market footprint is the appropriate path.

[3] ISO Tariff Section 4.13.5

The DERA model, the ISO's FERC Order 2222-compliant model, is a natural fit for aggregated DERs seeking to participate in ISO markets in a more equivalent manner to a generating resource that exports energy beyond the load curtailment amount. The DERA model also accommodates demand-response participation.

3. Export Considerations

Market-Wide: Considerations with Resource-Level Exports

This draft final proposal retains net exports being allowed by end-use customers and does not propose to allow DR resources to export beyond the resource level. Allowing a distributed resource aggregation to become a net exporter beyond the resource level would introduce additional modeling considerations for the Full Network Model (FNM). Today, demand response aggregations are modeled as load aggregations within a sub-LAP rather than as geographically distributed injections. For network modeling purposes, sub-LAP load is distributed across individual network nodes using load distribution factors that approximate the expected distribution of demand. While this approach is appropriate for aggregated load, allowing a geographically dispersed demand response aggregation to become a net exporter up to the sub-LAP may misrepresent the location of exports within the network model, as existing load distribution assumptions may not reflect the actual locations of those injections. As exports become a larger component of an aggregation's performance, differences between the assumed nodal distribution and the actual locations of exports could have a greater impact on modeled power flows, congestion management, and locational pricing.

Accordingly, while the ISO recognizes stakeholder interest in enabling demand response aggregations to become net exporters, evaluating alternative network modeling approaches and associated market design changes is beyond the scope of the incremental reforms proposed in DDEMI Track 1. Future evaluation could consider whether additional nodal visibility, revised resource modeling constructs, or alternative FNM representations are needed to accurately reflect geographically distributed exports while preserving reliable congestion management and efficient market outcomes. The ISO finds that these issues are more appropriately considered in a future phase of DDEMI, to align on policy and also discuss the necessary FNM enhancements, resource modeling, settlement implications, and operational impacts can be evaluated comprehensively before expanding export capability beyond the resource level.

ISO BAA Deliverability: Considerations with Resource-Level Exports

Even if the market design and FNM issues were solved, exports beyond a resource's own load raise a separate transmission planning and deliverability issue within the ISO BAA because deliverability is finite and already allocated.

Resources in the ISO BAA may request and, subject to the interconnection and study process, obtain deliverability status through the Generator Interconnection Process (GIP) or Distribution Generation Deliverability (DGD) process, both of which result in the allocation of Transmission Plan Deliverability (TPD). While this section’s discussion is grounded in the ISO’s role as the balancing authority and transmission planning authority, and therefore reflects how these issues are addressed within the ISO BAA/TP; it is not intended to establish or imply requirements for the broader market footprint beyond this context.

The purpose of the ISO BAA’s deliverability assessment is to demonstrate that the generating capacity in any electrical area can be run simultaneously, at stressed system conditions (generally peak load), and that the excess energy above load in that electrical area can be exported to the remainder of the control area, subject to contingency testing.

Moving forward with stakeholder proposals to allow exports beyond the resource level (Resource ID) could take deliverability away from other resources. Deliverability is finite and shared in the ISO BAA. In the ISO BAA deliverability study context, general load is already used to support deliverability for existing full and partial capacity resources. Exports beyond a resource’s own registered load would rely on that same general load and could therefore reduce deliverability available to other resources.

In other words, exports beyond the DR resource can take deliverability away that was already granted to other resources. Therefore, if a DR resource wishes to rely on this general load (not already included under its own market ID) to support resource-level generation export capabilities, it must proceed through the generator interconnection queue and obtain the appropriate transmission planning deliverability (TPD) allocations in the same manner that all other transmission and distribution interconnected exporting resources do. DR resources may use only their own customers’ load to support their curtailment capability—now and in the future.

The ISO BAA intentionally models and settles PDRs at the resource level, with demand response defined as a net load reduction by the market-participating aggregation as a whole rather than by individual participating customers. Track 1 preserves this longstanding construct by continuing to require that a PDR remain a net load-reducing resource at the resource level. Under this framework, limited exports by individual customers may occur within an aggregation, provided the aggregation as a whole continues to deliver net load curtailment to the ISO. These customer-level exports do not represent a change in Resource Adequacy or deliverability policy, nor do they alter the fundamental characterization of DR resources as load curtailment resources. A separate future policy question is whether DR resources should be allowed to provide exports beyond the resource level and become net exporting resources. Such an expansion would require additional consideration of whether and how exporting demand response resources would be studied and allocated Transmission Plan Deliverability (TPD) under the applicable transmission planning framework, as well as the resource modeling and market design considerations mentioned above.

Historically, DR resources received full capacity deliverability status (FCDS) through a 2005 grandfathering policy, but only for curtailment capability and at amounts existing at that time. Because the amounts of PDRs and RDRRs in the ISO BAA today are consistent with the amounts participating in 2005, all DR resources continue to hold FCDS. As such, the ISO gave PDRs an effective deliverability waiver, maintaining them all as FCDS. Existing assumed FCDS for PDRs and RDRRs applies only to load curtailment capability, and only to the levels that existed in 2005 for all load curtailment programs. If DR resource capacity were to grow by a material amount, the ISO may need to consider a new process for allocation of deliverability to DR resources similar to the TPD allocation process.

The original 2005 deliverability status grandfathering does not apply to exporting DR resources. If the definition of demand response were to be modified to include “negative curtailment” (exporting) at the resource level, the ISO must queue and model such exporting demand response in order to include them in deliverability studies, allocate their own TPD and assure they have no negative impact on the deliverability of other existing FCDS and PCDS resources or already queued resources with existing TPD allocations.

Non-Responsive Load Customers

Several stakeholders raised concerns regarding the potential enrollment of individual non-responsive load customers within the larger wholesale demand response aggregation. The ISO agrees that wholesale demand response resources should continue to represent genuine, dispatchable load flexibility for the individual customers that comprise the aggregation. Nothing in this proposal affects the obligations of DR resources to contract, bid, and perform as required. Demand response resources today may consist of customers with varying levels of responsiveness, and Track 1 does not modify the existing performance obligations of PDR or RDRR. Wholesale resources must continue to satisfy all applicable market requirements, including bidding obligations, settlement requirements, and performance expectations for PDR/RDRR, just as they do today. Wholesale compensation remains based on verified incremental performance during ISO dispatch intervals. The ISO and its Department of Market Monitoring actively review DR resources to ensure compliance with performance requirements. FERC's Office of Enforcement both recently and frequently has addressed this issue in other markets, levying heavy fines at DR providers.

The ISO also notes that Resource Adequacy accreditation and wholesale market performance are distinct processes governed by different authorities. Qualifying Capacity values are established by the applicable Local Regulatory Authority and are intended to reflect the expected reliability contribution of a resource. The ISO agrees that Resource Adequacy values should appropriately reflect actual resource capability and will continue coordinating with Local Regulatory Authorities as demand response participation evolves. However, changes to Local Regulatory Authority Resource Adequacy accreditation methodologies are outside of the jurisdiction of the ISO.

With respect to concerns regarding aggregation composition, the ISO concludes additional customer-level responsiveness requirements or aggregation design standards are outside the scope of this targeted settlement reform. The objective of Track 1 is to improve the measurement of authorized behind-the-meter export behavior within the existing demand response framework, not to redefine how demand response resources are accredited or assembled.

Finally, while some stakeholders suggested that allowing aggregation-level exports could reduce incentives to enroll non-responsive load, broader export capability would also require corresponding changes to generator interconnection, transmission deliverability, and planning frameworks. Any changes related to deliverability would occur in related deliverability policy processes.

Accordingly, the ISO is not proposing additional aggregation composition requirements or customer-level responsiveness standards as part of Track 1. The ISO will continue monitoring resource performance following implementation and will coordinate with market participants and Local Regulatory Authorities as experience is gained with broader participation by customers with distributed energy resources.

4. Interconnection Requirements

Utility Distribution Company Interconnection Review

Today, through the ISO's Demand Response Registration System (DRRS), utility distribution companies (UDCs) review and approve or reject customer location registrations submitted by demand response providers (DRPs) for participation in ISO demand response resources. The registration process serves several purposes, including preventing participation in multiple overlapping or conflicting demand response programs and enabling the UDC to verify that a customer's participation in an ISO demand response resource is consistent with the safe and reliable operation of the distribution system. As under the existing tariff, the designated Load Serving Entity and the UDC will continue to have an opportunity to review registration information and provide comments regarding its accuracy. Any disputes regarding the acceptance or rejection of a customer registration remain matters for the applicable Local Regulatory Authority (LRA) and are not subject to resolution through the ISO's dispute resolution process.

Stakeholders broadly agreed that customer exports should only be reflected in demand response energy measurement (DREM) when the customer has an approved interconnection agreement that authorizes exports. For example, for CPUC-jurisdictional utility distribution companies, a Rule 21 Export Interconnection Agreement satisfies this requirement.

Consistent with this feedback, the ISO proposes a limited enhancement to the DRRS location registration process. Specifically, DRRS will include attributes identifying those customer service accounts whose behind-the-meter exports are intended to be reflected in demand response performance measurement, and subject to implementation capabilities, potentially information on the level of export authorized under the customer's interconnection agreement. Similar to the information maintained for Distributed Energy Resource Aggregations (DERAs), this information will become part of the location registration data maintained by the ISO and will enable the UDC, as part of its existing registration review process, to verify that the customer has the appropriate interconnection authorization and that the resource is registered consistent with its authorized operating characteristics. The ISO also may use the data in its audits for DR resources.

Demand Response Providers will remain responsible for ensuring that all information submitted to the ISO regarding the operational and technical characteristics of their resources accurately reflects the physical capabilities of the underlying resources.

Participating customers also must comply with applicable UDC tariffs, operating procedures, interconnection requirements, and any applicable LRA requirements. Resources must operate consistently with any limitations established by the UDC, including authorized export capabilities. Scheduling coordinators remain responsible for ensuring that all information submitted to the ISO for the participation of PDRs and RDRR is true and accurate.

The purpose of the Track 1 enhancement is to support accurate resource representation via registration and modeling, not to create a new ISO function to monitor or enforce customer-specific distribution operating limits. Consistent with the existing allocation of responsibilities between the ISO and distribution utilities, the UDC remains responsible for establishing and enforcing distribution interconnection requirements, including authorized export capabilities. The ISO's role remains limited to administering wholesale market participation, including resource registration, dispatch, settlement, and compliance with ISO tariff requirements. As with DERAs, the ISO will rely on the UDC's review of registration information and will coordinate, as appropriate, with the Transmission Operator (TOP) and/or UDC to avoid conflicting operational directives or other operational issues.

The ISO does not believe this proposal creates an incentive for customer-level exports that exceed applicable interconnection limits. Demand response providers and scheduling coordinators remain responsible for ensuring that resource information, availability, and bids submitted to the ISO are consistent with applicable Utility Distribution Company requirements, including authorized export capabilities and other applicable distribution operating limitations, as well as the ISO tariff. Bidding demand response capability that would require exports beyond those authorized limits would be inconsistent with the resource's registered operating characteristics and applicable UDC requirements. Collecting authorized export capability through DRRS creates an auditable record of the resource's registered operating characteristics while preserving the existing division of responsibilities between the ISO and the UDC. The ISO will continue to perform settlement validation, meter data quality checks, and market monitoring activities associated with compliance with ISO tariff requirements. The ISO also notes that UDCs and LSEs may remove customers from DR resources after the registration process if certain customers violate interconnection limits.

5. Settlement and Performance Measurement

Scheduling Coordinator Role in Applying Export Limits

Stakeholders broadly supported allowing Scheduling Coordinators (SCs) to determine how resource-level export limits are applied within a demand response aggregation in the comments received on the revised straw proposal. The ISO agrees with this recommendation because SCs are already responsible for calculating and submitting settlement-quality meter data and are therefore best positioned to implement the resource-level export limit in a manner consistent with existing settlement responsibilities.

Under the proposal, intervals in which aggregated customer meter data is negative during a demand response dispatch period will continue to be capped at zero at the resource level. However, the proposal does not prescribe which individual exporting end-use customers within the aggregation must be adjusted to achieve that outcome. Consistent with stakeholder feedback, the ISO proposes that SCs retain the responsibility and flexibility to apply the resource-level export limit as part of their meter data calculations, including determining how the necessary adjustments are allocated among participating customers within the aggregation.

PEM Application

Under the ISO's participation models, the DRP submits additional performance data to support the SC's participation in the wholesale markets on behalf of the end-use customers within the aggregation. There is already a practice today of zeroing out exporting intervals when DRPs use the MGO PEM.[4] This proposal extends consistent treatment across all PEMs, including day matching, weather matching, control group, MGO, and any other applicable approaches.

The ISO proposes to apply this framework uniformly to all PEMs. Regardless of the methodology used, the resource level export limit will apply. The ISO does not differentiate across PEM types for purposes of this proposal, as the focus is on accurately accounting for customer behavior during DR dispatch intervals.

Capturing export behavior is not just important during demand response dispatch events, but also important to capture to the extent it represents typical behavior. To

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[4] ISO Tariff Section 4.13.4.2 (a) and (d)

ensure consistency and accurate compensation, baseline calculations must also reflect regular export behavior during non-event intervals. Capturing both export behavior during dispatch and typical export patterns outside of events ensures that compensation reflects incremental wholesale demand response service above typical behavior.

Proposal

The ISO proposes to retain the existing wholesale demand response construct while refining the measurement practices used to evaluate the amount of demand response provided by individual customers within the wholesale resource aggregation. At the wholesale resource level, demand response resources cannot produce net export in any interval. Under such a limit, SCs are required to replace the *aggregated* customer load meter data with a zero value for any interval where that meter data is negative. The Track 1 modification removes the existing restriction preventing the aggregation from measuring exports at the end-use customer level when those customers are authorized under their interconnection agreements to export energy. This maintains the existing wholesale definition of demand response as a load curtailment product while more accurately measuring the additional usable capability provided by individual end-use customers in the aggregation. This change does not authorize exports as a demand response product but rather refines how existing end-use customer behavior is measured within aggregated resources.

Proposal Examples

Today's rules: illustrative DREM calculation for a single end-use customer with behind-the-meter energy storage

	RT interval					
HE 19	1	2	3	4	5	6
Baseline value	1.5 kW	1.75 kW	2.0 kW	2.0 kW	2.0 kW	2.0 kW
Actual load during dispatch	0.5 kW	-3.0 kW	-3.0 kW	-3.0 kW	-3.0 kW	-3.0 kW
Zeroed out load during dispatch	0.5 kW	0.0 kW	0.0 kW	0.0 kW	0.0 kW	0.0 kW
DR Energy Measurement	1.0 kW	1.75 kW	2.0 kW	2.0 kW	2.0 kW	2.0 kW

The intervals highlighted in yellow above represent periods where the customer was exporting energy onto the distribution system but the DR provider had to replace the negative meter values in the “actual load during dispatch” row with zeroes to comply with the ISO’s current DR metering rules. Under this proposal, the DR provider would not be required to replace these values with zeroes for the same customer above. Instead, the customer level DREM calculation would appear as below.

Proposed change: illustrative DREM calculation for a single end-use customer with behind-the-meter energy storage

	RT interval					
HE 19	1	2	3	4	5	6
Baseline value	1.5 kW	1.75 kW	2.0 kW	2.0 kW	2.0 kW	2.0 kW
Actual load during dispatch	0.5 kW	-3.0 kW	-3.0 kW	-3.0 kW	-3.0 kW	-3.0 kW
DR Energy Measurement	1.0 kW	4.75 kW	5.0 kW	5.0 kW	5.0 kW	5.0 kW

The intervals highlighted in green above represent periods where, under this proposal, the actual load is *no longer* being zeroed out. Under today’s rules, the SC would have replaced these values with zero. The calculation in this example results in higher DREM values for this end-use customer.

Proposed change: illustrative aggregated resource-level DREM calculation

At the resource level, below is a hypothetical example PDR comprised of four aggregated customers showing the application of the new rule removing the end-use customer limit on exports and enforcing the resource limit on exports.

End-use customer	**1**	**2**	**3**	**4**	**Total**
Baseline value	2.0 kW	2.0 kW	2.0 kW	2.0 kW	8 kW
Actual load during dispatch	*0.5 kW*	*0.0 kW*	*-3.0 kW*	*-3.0 kW*	*-5.5 kW*
Uncapped DREM	*1.5 kW*	*2.0 kW*	*5.0 kW*	*5.0 kW*	*13.5 kW*
Capped load during dispatch					0.0 kW
Capped DREM					8.0 kW

The "actual load during dispatch" row indicates the end-use customer energy measurements during a dispatch period. The negative values for customer 3 and customer 4 represent exports onto the distribution system from those customers during the dispatch interval. The "uncapped DREM" row indicates the simple difference between the baseline value and the actual load. However, in applying the new rule enforcing the resource limit on exports, the sum total column in the "actual load during dispatch" row (-5.5 kW) would be replaced by 0.0 kW in the "Capped aggregated load during dispatch" row in order to enforce the resource-level aggregate export limit. In total, the DREM for this dispatch period for the resource would be 8.0 kW—the value in the "capped DREM" row.

6. Baselines and Performance Measurement

Baseline Calculations

Existing baseline methodologies including the 10-in-10, 5-in-10, and weather-matching approaches estimate what a customer's electricity consumption would have been absent dispatch. Under the Track 1 proposal, that expected behavior appropriately includes routine BTM battery charging, discharging, and exports where those behaviors are representative of normal operations. Accordingly, exports should continue to be reflected in baseline calculations.

Pre-event Baseline Adjustment Factors

Stakeholders generally agreed that existing baseline methodologies should continue to be used but raised concerns that the existing pre-event adjustment factor was not designed for customers that routinely export energy. A baseline adjustment factor is a value used to fine-tune a customer's baseline estimate, which is the amount of electricity the customer would have been expected to use absent a demand response event, so that the baseline more accurately reflects the customer's actual operating conditions on the event day.[5] The ISO agrees that targeted revisions are warranted. However, the ISO does not support systematically capping adjustment factors at 1.0 because doing so would systematically eliminate downward adjustments while retaining upward adjustments embedded in the historical baseline, potentially reducing measurement accuracy.

As background, because operating conditions on the event day may differ from historical conditions, CAISO baselines allow for a pre-event adjustment factor, calculated as the ratio of the average customer load over the second, third, and fourth hours preceding the demand response event to the corresponding historical baseline period. The proposal does not modify this adjustment period. Rather, it clarifies how average load is calculated within that period when settlement intervals reflect customer exports.

[5] For example, in the 10-in-10 load baseline methodology, the scheduling coordinator multiplies the would-be baseline value by a percentage equal to the ratio of (i) the average load of the DR resources during the second, third, and fourth hours preceding the hour of the trading day to (ii) its average load during the same second, third, and fourth hours of the baseline calendar days. This adjustment must be capped at 20 percent (up or down).

Example 1: Existing methodology (today)

Under the current methodology, the adjustment factor is calculated as the ratio of the customer's average net load during the pre-event adjustment period on the event day to the corresponding average hourly net load from the historical baseline period.

	Average Net Load from the Historical Baseline Period (kW)	Event Day (kW)
Average pre-event load	100	90

Adjustment Factor = 90 ÷ 100 = 0.90

If the historical event baseline is 500 kWh, the adjusted baseline becomes:
500 kWh × 0.90 = 450 kWh

This reflects that the customer's operating conditions immediately before dispatch were approximately 10 percent lower than during the historical baseline period.

Because the customer's average pre-event load on the event day (90 kW) is 10% lower than the average pre-event load during the historical baseline period (100 kW), the adjustment factor reduces the event baseline by the same amount. Applying the 0.90 adjustment factor lowers the historical event baseline from 500 kWh to 450 kWh, aligning the baseline with the customer's actual operating conditions immediately before the event. This adjustment helps ensure that demand response performance reflects load reductions attributable to the dispatch event rather than lower consumption levels that already existed before the event began. Without the adjustment, the customer would be measured against the unadjusted 500 kWh baseline and could receive compensation for 50 kWh of apparent load reduction that was not caused by the dispatch event. Failing to adjust the baseline would overstate demand response performance and could result in compensation for reductions that had already occurred prior to the event rather than for actual event-driven load curtailment.

Example 2: Problem introduced by behind-the-meter exports

Under the Track 1 proposal, a customer's expected operating behavior may include battery exports, shown as negative load at the customer meter, during the pre-event adjustment period.

	Average Net Load from the Historical Baseline Period	Event Day (kW)
Average pre-event net load	-15	60

Adjustment Factor = 60 ÷ (-15) = -4.0

Applying a negative adjustment factor would invert the customer's historical baseline and produce a result that is not representative of expected operating behavior.

Similarly, if the historical pre-event average net load equals zero (*e.g.,* imports and exports offset), the adjustment factor becomes undefined due to division by zero.

These outcomes reflect a limitation of the existing adjustment factor construct when applied to resources whose normal operation includes exports.

Potential approaches for addressing pre-event adjustment factors when exports result in negative or undefined values

As discussed above, the ISO finds the historical baseline should continue to reflect a customer's expected operating behavior, including routine BTM battery charging, discharging, and exports. In cases when the historical average pre-event net load is zero or negative, there are several potential approaches that could be considered.

Option 1: Exclude export intervals from the adjustment factor calculation

Under this approach, the historical baseline would continue to include all customer behavior, including exports. However, when calculating the pre-event adjustment factor, settlement intervals within the existing pre-event adjustment period in which the customer is exporting would be excluded from the adjustment factor calculation. The adjustment factor would instead be calculated using only qualifying settlement intervals with positive customer load.

This approach preserves the existing purpose of the adjustment factor, to account for day-of operating conditions, while avoiding mathematically invalid results caused by export intervals.

Example

Settlement Interval (within the pre-event adjustment period)	Average Net Load from the Historical Baseline Period (kW)	Event Day (kW)
1	-20 (export)	-15 (export)
2	50 (import)	60 (import)

Rather than averaging both intervals, the export interval (settlement interval 1) is excluded from the adjustment factor calculation.

Adjustment Factor = 60 ÷ 50 = 1.2

The historical baseline itself continues to reflect both export and import behavior; only the adjustment factor calculation is modified. This approach preserves the existing baseline methodologies and continues to reflect customer-specific operating conditions while ensuring that adjustment factors remain mathematically valid by avoiding undefined, negative, or otherwise anomalous results caused by export intervals. In addition, it requires only limited changes to existing market systems and would be triggered only in relatively infrequent circumstances when exports would otherwise prevent a valid adjustment factor from being calculated. However, excluding export intervals from the adjustment factor calculation may result in the adjustment factor being based on a narrower subset of customer behavior and could reduce its ability to fully reflect actual day-of operating conditions for customers that regularly alternate between importing and exporting energy. Stakeholders also may question the consistency of including exports in the historical baseline while excluding them from the adjustment factor calculation, particularly if the resulting performance measurement differs from what would occur under a methodology that considers all intervals equally. As a result, this approach represents a tradeoff between maintaining simplicity and mathematical validity versus preserving full symmetry between baseline and adjustment factor calculations on the other.

Option 2: Use a Proxy or Aggregation Adjustment Factor

Rather than using the individual customer's pre-event behavior, an alternate adjustment factor could be derived from another source, such as: the DR aggregation, another customer within the aggregation, or another system-level proxy. The customer's historical baseline would remain unchanged, but the adjustment factor would no longer be based on that customer's own pre-event operating conditions.

Example

Assume the customer's adjustment factor cannot be calculated because the historical pre-event average load equals 0 kW. Rather than using customer-specific data, the ISO could apply the adjustment factor calculated for the overall aggregation.

Customer	Average Net Load from the Historical Baseline Period (kW)	Event Day (kW)
Individual Customer	0	50
Aggregation Average	120	108

Aggregation Adjustment Factor = 108 ÷ 120 = 0.90

The customer's historical baseline would then be multiplied by 0.90.

The historical baseline itself would remain unchanged, but the adjustment factor would be derived from a proxy source rather than the customer's own pre-event behavior. This approach ensures that an adjustment factor can be calculated in all circumstances, including cases where customer-specific data would otherwise produce undefined or mathematically invalid results. It also continues to account for day-of operating conditions and may provide a practical solution for customers whose load profiles regularly include exports or other behaviors that complicate traditional adjustment factor calculations. However, because the adjustment factor is no longer based on the customer's actual operating conditions, the resulting baseline adjustment may not accurately reflect that customer's behavior on the event day. The approach therefore introduces the risk of over or under adjusting customer performance depending on how closely the selected proxy aligns with the customer's actual operating profile. In addition, the use of aggregation-level or other proxy factors could lead to differences in settlement outcomes among similarly situated customers and would require additional rules governing the selection, application, and oversight of appropriate proxy methodologies. As a result, this approach represents a tradeoff between ensuring universal applicability of the adjustment factor and maintaining a direct relationship between performance measurement and the individual customer's observed operating conditions.

Option 3: Default the adjustment factor to 1.0

Under this approach, whenever the adjustment factor cannot be calculated, the historical baseline would simply be used without adjustment. This effectively assumes the customer's operating conditions on the event day are identical to those represented by the historical baseline.

	Average Net Load from the Historical Baseline Period (kW)	Event Day (kW)
Average Pre-Event Load	0	60

Because the adjustment factor cannot be calculated, the scheduling coordinator would simply apply an adjustment factor of 1.0. Therefore, if the historical event baseline equals 500 kWh, the adjusted baseline remains:

500 kWh × 1.00 = 500 kWh

The historical baseline itself would remain unchanged, but whenever a valid adjustment factor cannot be calculated, a default adjustment factor of 1.0 would be applied. This approach is simple, transparent, and easy to implement, requiring no additional calculations, proxy methodologies, or special treatment of export intervals. It also avoids mathematically invalid results while preserving the existing baseline methodology. However, by assuming that event-day operating conditions are identical to the historical conditions reflected in the baseline, this approach does not account for legitimate day-of variations in customer behavior. As a result, it may overstate or understate expected consumption when factors such as weather, occupancy, operational schedules, or DER performance differ materially from historical conditions. This risk is not insignificant. DR resources frequently provide demand response in the highest-priced hours of the highest-priced days, conditions that would not have appeared during their baseline days. Although a “no adjustment” approach is simple, it muffles correct market incentives and compensation on days when they are most critical.

Proposed Hierarchical Approach

o address the limited circumstances in which BTM export behavior results in undefined or negative pre-event adjustment factors, the ISO proposes a hierarchical framework for calculating adjustment factors. This framework preserves existing baseline methodologies while applying targeted corrections only when necessary to produce mathematically valid and representative results. The proposed modifications do not alter the underlying baseline calculation, the tariff-defined pre-event adjustment period, or the existing adjustment-factor construct. Existing tariff limits on adjustment factors also continue to apply. Under the proposal, settlement intervals that reflect net exports are excluded from the calculation of average pre-event load only when their inclusion would result in an undefined, negative, or otherwise non-representative adjustment factor. Historical baseline calculations continue to reflect all customer operating behavior, including both imports and exports.

The proposed framework consists of the following steps:

- **Step 1:** Apply the existing adjustment-factor methodology.
- **Step 2:** If application of the existing methodology results in an undefined adjustment factor, a negative adjustment factor, or another mathematically anomalous result due to net-export intervals, exclude settlement intervals with net exports from the calculation of the average pre-event load. Recalculate the adjustment factor using the remaining qualifying settlement intervals, provided the remaining data satisfy existing baseline data sufficiency requirements.
- **Step 3:** If the remaining data do not satisfy existing baseline data sufficiency requirements, use an adjustment factor of 1.0.[6]

This hierarchical framework is intended to ensure both mathematical validity and policy consistency. It preserves the existing methodology as the default approach by retaining current baseline and adjustment-factor constructs whenever they produce valid and representative results. At the same time, it applies a narrowly tailored correction only when necessary to address mathematical distortions associated with net-export intervals without altering the underlying baseline design. The framework also avoids

[6] While the ISO considered the use of proxy adjustment factors, the ISO is not proposing that approach because proxy values are not derived from the customer whose baseline is being adjusted and therefore may not accurately reflect that customer's actual operating conditions on the event day. Using a proxy adjustment factor reduces the ability to reflect individual customer operating behavior and can result in inconsistent treatment across similarly situated resources. It would also introduce additional implementation complexity and governance requirements, particularly around proxy selection, and rely on external assumptions that are not grounded in customer-specific data.

reliance on external or proxy data sources, thereby maintaining a focus on customer-specific operating data. Finally, it minimizes implementation complexity and helps mitigate potential gaming opportunities.

The ISO anticipates that implementation of this framework will require only limited modifications to existing baseline calculation processes because it preserves the current adjustment-factor construct and applies export-interval exclusions only in the limited circumstances where mathematically valid results would otherwise not be obtained. The ISO will continue to monitor baseline adjustment outcomes and may revisit this issue in the future if stakeholders identify a need for further enhancements.

Step 1: Apply existing methodology

SCs will first apply the existing pre-event adjustment factor methodology using all available pre-event intervals, consistent with current tariff rules and baseline constructs (e.g., 10-in-10, 5-in-10, etc.). If the resulting adjustment factor is mathematically valid and representative of expected operating conditions, no further action is required, and the historical baseline and calculated adjustment factor are applied without modification.

Example A: Existing Methodology Applies (No Change)

	Average Net Load from the Historical Baseline Period (kW)	Event Day (kW)
Average pre-event load	100	90

Adjustment Factor = 90 ÷ 100 = 0.90

If the historical event baseline is 500 kWh: 500 × 0.90 = 450 kWh

Example: Denominator Equals Zero

Settlement Interval (within the pre-event adjustment period)	Historical Baseline (kW)	Event Day (kW)
1	-20	90
2	20	30

Historical average = 0.

Adjustment factor is undefined.

Step 2: Exclude export intervals

If Step 1 produces an undefined or non-representative adjustment factor due to export behavior, settlement intervals reflecting net export are excluded from the calculation of the average pre-event load used in the adjustment factor. The adjustment factor shall then be recalculated using the remaining qualifying settlement intervals, provided the remaining data satisfy existing baseline data sufficiency requirements. If these conditions are not met, proceed to Step 3. The historical baseline remains unchanged and continues to reflect all customer operating behavior, including exports. This step preserves the customer-specific nature of the adjustment factor while addressing mathematical distortions introduced by persistent export behavior.

Example B: Export Behavior Produces a Negative Result

Settlement Interval (within the pre-event adjustment period)	Average Net Load from the Historical Baseline Period (kW)	Event Day (kW)
1	-30	80
2	0	40
Average net load	-15	60

Adjustment Factor = 60 ÷ (-15) = -4.0

This result produces a negative adjustment factor. Because the resulting adjustment factor is negative, Step 2 applies and the adjustment factor is recalculated after excluding export intervals from the adjustment-factor calculation. Following recalculation, the resulting adjustment factor remains subject to the existing tariff limits of 0.80 to 1.20.

Example C: Mixed Import and Export Intervals

Settlement Interval (within the pre-event adjustment period)	Historical Baseline (kW)	Event Day (kW)
1	-20 (export)	-15 (export)
2	40 (import)	50 (import)
3	60 (import)	66 (import)

Excluding the export interval leaves two qualifying import intervals. The average pre-event load is therefore calculated using those remaining intervals. The adjustment factor is therefore calculated as:

Adjustment Factor = (50 + 66) ÷ (40 + 60) = 116 ÷ 100 = 1.16

Step 3: If there is insufficient data, default to an adjustment factor of 1.0

If the remaining qualifying settlement intervals do not satisfy the existing baseline data sufficiency requirements after excluding export intervals, the adjustment factor shall default to 1.0.

Example D: All Intervals Are Exports and No Valid Data Remains

Settlement Interval (within the pre-event adjustment period)	Historical Baseline (kW)	Event Day (kW)
1	-10	-15
2	-20	-25
3	-5	-10

When no qualifying import intervals remain, the tariff-prescribed adjustment factor cannot be calculated because no representative average load exists. Applying an adjustment factor of 1.0 preserves the historical baseline without introducing arbitrary proxy values.

7. Net Energy Metering/ Net Billing Tariff Participation

The DDEMI Track 1 proposal would allow the performance of a demand response aggregation to include behind-the-meter exports from individual customers, provided the aggregation, as a whole, does not net export. Customers participating under CPUC Net Energy Metering and the Net Billing Tariff are already eligible to participate in Proxy Demand Response and other applicable wholesale demand response programs as load curtailment only (without for exports). The Track 1 proposal does not expand wholesale market eligibility or establish a new compensation mechanism. Rather, it removes an existing settlement restriction that requires authorized customer exports to be excluded when measuring the performance of a demand response aggregation. While this proposal is intended to remove barriers to accurately reflecting the capabilities of customers with DERs, the CPUC's Energy Division staff and Cal Advocates Office expressed concern that the proposal would create circumstances in which the same exported energy receives compensation through both retail and wholesale mechanisms.

The California IOUs similarly recommended the ISO ensure double compensation concerns are addressed.

Specifically, the CPUC Energy Division staff explained the Net Billing Tariffs of the three Investor Owned Utilities that calculate customer export credits using the avoided cost of energy for all 8,760 hours of the year, as well as hourly values for avoided capacity, avoided greenhouse gas emissions, and other attributes. CPUC Energy Division staff asserted that Net Billing Tariff customers already receive energy payments for their exports based on the value of each kWh of energy they export to the grid. They similarly stated that Net Energy Metering tariffs compensate customers one-to-one for exports with retail energy credits, and the value of those energy credits is the retail rate the customer would otherwise pay, and those retail rates are designed to recover all utility cost components, including specific cost components based on marginal energy and marginal capacity costs that recover generation costs.

CPUC Energy Division staff further asserted that every kWh of that export from an end-user with a Net Energy Metering or Net Billing Tariff under the proposed modification for PDR or RDRR would be paid twice: 1) for energy value as exports to the grid under Net Energy Metering and the Net Billing Tariff; and 2) as wholesale energy payments.

The ISO evaluated and discussed stakeholder concerns raised throughout the stakeholder process and concludes that the Track 1 proposal does not result in compensation for the same energy product or service. The ISO notes that retail export compensation and wholesale demand response compensation compensate fundamentally different energy products under separate regulatory frameworks. Retail export compensation is established through CPUC policy to compensate eligible exported energy based on avoided system costs and does not require dispatchability or operational performance, even though it may result in behavioral load shifting and exports to support grid reliability. In contrast, wholesale demand response compensation is earned only when a resource is economically selected or dispatched by the ISO, responds to ISO dispatch instructions, and provides measurable, incremental energy performance during periods of system need.

Importantly, the inclusion of projections of forward wholesale energy prices within the avoided cost calculator (ACC) does not alter the fundamental nature of retail export compensation. The ACC is an *ex ante* valuation methodology used to establish retail compensation levels based on projected system benefits and avoided costs. Wholesale market compensation, by contrast, is determined through *ex post* market outcomes and is based on actual resource performance. As a result, both frameworks compensate for energy value, they however compensate distinct services using different methodologies and performance requirements.

The Track 1 proposal does not change what the wholesale market compensates. Rather, it removes an existing settlement calculation restriction that prevents authorized customer exports from being reflected when measuring the incremental demand response capability of an aggregation. Wholesale resources will continue to be compensated by wholesale markets only for incremental performance relative to an established baseline. Because customer baselines continue to reflect normal operating behavior (i.e., behind-the-meter charging, discharging, and export patterns) routine exports remain embedded in the baseline and are not separately compensated through the wholesale market. Only incremental changes in customer behavior resulting from ISO energy dispatch are eligible for wholesale compensation.

The ISO recognizes that an administrative retail tariff framework, by nature of its design, will credit this incremental energy as a result of CAISO wholesale market dispatch at the retail level at the predetermined ACC price (in the case of the Net Billing Tariff) or at retail rates (in the case of the Net Energy Metering tariff). These projected values are set in advance based on static forecasts. We see these frameworks as separate, since the DDEMI proposal will help shape customer incentives and behavior in real-time by using wholesale dispatch and compensation to lead to incremental wholesale energy performance in times of grid stress.

Participation in the wholesale market also requires resources to satisfy all existing ISO market requirements, including aggregation rules, bidding requirements, metering and telemetry requirements, performance obligations, and settlement validation. Wholesale compensation through PDR/RDRR is therefore contingent upon market participation and demonstrated performance. Resources remain subject to existing market consequences for non-performance, including resource adequacy availability requirements where applicable and settlement adjustments when performance obligations are not met.

For these reasons, the ISO does not propose to exclude retail customers participating under Net Energy Metering or the Net Billing Tariff from participation in a wholesale aggregation through Track 1. The Track 1 proposal does not create a new wholesale product or compensate customers merely for exporting energy. Rather, it removes an unnecessary settlement limitation that prevents demand response aggregations from more accurately reflecting the aggregate capabilities of its individual customers while preserving the fundamental demand response principle that wholesale compensation is based solely on incremental performance. The ISO will continue coordinating with the CPUC as retail and wholesale participation frameworks evolve.

Governing Body Classification

This initiative will update how demand response is measured when the demand response is participating in the markets operated by the ISO. This includes enhancements to PDR/RDRR export rules and settlement methodologies. Because these market rule changes would apply to WEIM/EDAM Entity BAAs, rather than solely the ISO balancing authority area, they fall under the WEM Governing Body's primary authority.

The WEM Governing Body has primary authority over any:

> proposal to change or establish a tariff rule applicable to the WEIM/EDAM Entity balancing authority areas, WEIM/EDAM Entities, or other market participants within the WEIM/EDAM Entity balancing authority areas, in their capacity as participants in WEIM/EDAM… The scope of this primary authority excludes, without limitation, any other proposals to change or establish tariff rule(s) applicable only to the ISO balancing authority area or to the ISO-controlled grid. Charter for WEIM and EDAM Governance § 2.2.1. The proposed tariff changes would be "applicable to WEIM/EDAM Entity balancing authority areas, WEIM/EDAM Entities, or other market participants within WEIM/EDAM Entity balancing authority areas, in their capacity as participants in WEIM/EDAM."

The changes proposed in Track 1 will not be limited to the ISO balancing authority area or to the ISO-controlled grid. Accordingly, the proposed changes fall within the scope of the WEM Governing Body's primary authority.

Next Steps

The ISO seeks stakeholder input on a set of targeted settlement changes and broader market participation options designed to expand demand flexibility across the Western market footprint. Stakeholder feedback on this draft final proposal will inform the development of a final proposal for DDEMI Track 1.

The ISO plans to host a virtual stakeholder meeting to discuss this revised straw proposal on July 9, 2026. Comments on this draft final proposal are due to the ISO on July 16, 2026.