BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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07/27/26
04:59 PM
R2106017

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resource Future.	Rulemaking 21-06-017

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) COMMENTS ON DISTRIBUTED ENERGY RESOURCES ORCHESTRATION WORKSHOP REPORTS

WILLIAM YU

Attorney for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-1634
E-mail: William.W.Yu@sce.com

Dated: **July 27, 2026**

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Pursuant to the July 9, 2026 *Assigned Commissioner's and Administrative Law Judge's Ruling Issuing Questions on the Distributed Energy Resources Orchestration Workshop Reports* ("Ruling"), Southern California Edison Company ("SCE") hereby submits its comments on the Distributed Energy Resources Orchestration Workshop Reports and questions presented in the Ruling.

Respectfully submitted,

WILLIAM YU

/s/ William Yu

By: William Yu

Attorney for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-1634
E-mail: William.W.Yu@sce.com

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Attachment

Southern California Edison Company's Comments on Distributed Energy Resources Orchestration Workshop Reports

Introduction

Disclaimer: This common introductory statement is intentionally included in two sets of related comments, filed simultaneously in Tracks 2 and 3 of R.21-06-017, on July 27, 2026.

Southern California Edison Company (SCE) appreciates the Commission's continued leadership in examining how load flexibility can support California's electrification, affordability, reliability, and grid modernization objectives. Taken together, the Track 2 distributed energy resources (DER) Orchestration workshops and the Track 3 Assigned Commissioner's Proposal on Flexible Service Connections ("FSC") reflect a common and increasingly important vision: a future distribution system that incorporates more flexible load, is more visible, more responsive, and better able to integrate customer-owned resources while making efficient use of existing infrastructure and supporting customer affordability. Track 2 and Track 3 should therefore work in concert to answer questions regarding customer participation, architecture, dependability, planning integration, and resource valuation to ensure that California develops a coherent flexibility framework that supports both near-term speed-to-power and long-term grid transformation.

SCE has already made great strides in these areas. Its Load Control Management System (LCMS) pilot, concluded after two years in January 2026, proved many of the foundational concepts required to allow customers to temporarily limit their load in exchange for earlier energization. SCE has similarly tested some critical concepts of long-term load flexibility through recent customer pilot programs. Additionally, SCE's Electrification Impacts Study (EIS) Part 2, filed in January 2026, explored demand flexibility potential, while new capabilities that would be enabled by Advanced Metering Infrastructure 2.0 (AMI 2.0) were described in SCE's AMI 2.0 application, A.26-03-030, filed March 2026.

It is with this background that SCE commends the Commission in correctly identifying several trends that are reshaping distribution system planning and operations, including growing electrification demand, increasing penetration of customer-owned DERs, the opportunity for increased load management leading to efficient utilization of existing infrastructure, and the importance of accelerating customer energization. The concepts reflected across both tracks—including speed-to-power solutions, advanced metering capabilities, DER management systems (DERMS), customer flexibility, operating envelopes, and utility-enabled orchestration—are aligned with capabilities SCE is actively developing and deploying.

It is clear that flexibility should play a larger role in the future grid. Utilities, aggregators, and technology providers should continue developing new approaches to support it. The question now is what are the technical capabilities, operational frameworks, customer engagement methodologies, and policy structures necessary to cost effectively realize that potential at scale . To answer these questions, California must effectively transition from promising concepts and demonstrations to scalable implementation while preserving sufficient flexibility to quickly learn, refine, and optimize those approaches over time.

Because the two tracks are examining different dimensions of the same evolving flexibility ecosystem, they also increasingly intersect. In particular, both tracks are evaluating concepts that depend on advanced visibility, communications, DER management capabilities, customer participation, and flexible load management. Both proceedings contemplate the potential for flexibility to support affordability objectives by deferring or avoiding certain infrastructure investments, accelerating speed to power, and efficiently utilizing existing assets. Both proceedings raise questions regarding architecture, customer participation, performance validation, and utility operational roles. This growing overlap creates both an opportunity and a risk if not closely coordinated.

The opportunity is that California can develop a robust flexibility framework that allows implementation, pilot learning, customer participation, utility modernization, and regulatory development to reinforce one another. In this respect, Track 2 and Track 3 should be viewed as mutually supportive efforts that collectively advance the Commission's goals for affordability, reliability, electrification, and customer choice. The risk is that policy decisions could prematurely narrow implementation pathways, architecture choices, planning assumptions, or flexibility models before sufficient operational experience is available to determine which approaches provide the greatest customer value.

Accordingly, SCE recommends that the Commission approach both tracks through a common set of guiding principles:

1. **Allow implementation and learning to proceed together.** Program deployment, framework development, and regulatory refinement should be done in parallel rather than sequentially, and be intentionally mutually reinforcing.
2. **Preserve flexibility in architecture and implementation.** Advanced capabilities such as AMI 2.0, Enterprise DERMS, Grid Edge DERMS, operating envelopes, and customer integration platforms will enable the foundational capabilities needed to support broader DER orchestration, but further insights are needed to provide the most robust framework.
3. **Recognize that long-term demand flexibility requires additional development.** Durable flexibility capable of use in planning for the purpose of capital deferral presents questions regarding customer participation, compensation, validation, and integration that warrant continued development and coordination across both tracks.
4. **Account for SCE's unique system topology.** SCE's electric system includes a distinct "middle layer" between the conventional radial distribution grid and the transmission system. This CPUC-jurisdictional networked subtransmission system introduces additional limitations and complexities that must be fully considered when developing Flexible Service Connection offerings and a broader DER Orchestration framework.

With these principles in mind, SCE offers the following roadmap to assist the Commission in modifying the Track 2 and Track 3 processes to create a coordinated implementation-and-learning pathway.

- **Track 2** should establish the framework and facilitate the operational activities that will determine when flexible load and customer-owned DERs can be treated as dependable planning resources, including performance standards and validation requirements. This approach allows the Commission to advance its flexibility vision while ensuring that implementation decisions are informed by operational experience without unnecessarily restricting the solution space.
- **Track 3** should continue to advance customer-facing flexibility solutions, with a focus on mechanisms supporting implementation of dynamic FSCs, but should avoid adopting prescriptive statewide solutions before customer participation, performance, architecture, compensation, and planning-treatment issues are sufficiently developed.[1] As the best solutions come into focus, whether on an IOU-specific or statewide level, they can be adopted within regulatory processes established in Track 2.

As the vision for DER Orchestration and Flexible Service Connections evolves, insights from scalable programs and operational experience may necessitate incremental investments in enabling capabilities. A clear and durable funding mechanism is needed to support these investments and ensure progress toward the end-state vision.

Ultimately, SCE believes the Commission is largely headed in the right direction. The proposals and questions presented in the twin Rulings identify many of the capabilities that will be necessary to support California's future grid. The challenge now is preserving sufficient flexibility within the policy framework to determine which approaches, architectures, customer arrangements, and orchestration models ultimately deliver the greatest affordability, reliability, customer benefit, and grid value for Californians.

Responses to questions 1-18 of the Assigned Commissioner's and Administrative Law Judge's Ruling Issuing Questions on the Distributed Energy Resources Orchestration Workshop Reports follow below.

Question 1

Are there any factual inconsistencies or areas needing clarification in the summary workshop reports set out in Attachments 1 and 2. Are the party perspectives discussed in the respective reports accurate?

[1] In sharing this roadmap, SCE relies in part on R. 21-06-017, *Assigned Commissioner's and Administrative Law Judge's Ruling Seeking Additional Information From Parties, Setting Forth Further Direction, and Modifying Schedule for Track 3*, Feb. 7, 2025, pp. 3-4, which stated the following: "[Track 3] will address medium- and longer-term mechanisms for the implementation of dynamic (*i.e.*, non-firm) flexible grid connections. Track 2 of this proceeding will address operational aspects to facilitate more efficient use of these mechanisms within the distribution system and bridging opportunities for grid expansion to meet the state's broader decarbonization goals … A separate ruling in Rulemaking 24-01-018 (the Energization Proceeding) will clarify the next steps for that proceeding to consider near-term solutions for flexible service connections related to static and less granular (*i.e.*, firm capacity) import limits."

The workshop reports generally capture the major positions discussed in the workshops, but several areas warrant clarification to ensure the record accurately reflects SCE's framework development and operations concerns. The workshop agenda did not elicit feedback on all necessary topics.

To be considered a dependable solution in addressing grid needs, DER orchestration requires a unique combination of grid visibility, operational coordination, and performance validation. SCE further notes that the relevant technology and market layers should be understood as complementary and necessary components of a broader orchestration architecture, rather than as fungible substitutes. These layers include enterprise Distributed Energy Resource Management System (DERMS), grid-edge DERMS, Advanced Distribution Management Systems (ADMS), Advanced Metering Infrastructure (AMI), aggregator platforms, original equipment manufacturer (OEM) capabilities, and customer-side systems.

SCE supports the Commission's efforts to utilize DER orchestration to meet future grid needs, but it must be implemented with a high degree of reliability, predictability, and sustained performance under real-world operating conditions. If these resources are to serve as an alternative to traditional grid investments, utilities must deploy the necessary technology, processes, and programs to ensure these resources consistently deliver the expected capacity and operational benefits when and where they are needed. SCE believes the best way to unlock the benefits of DER orchestration is to launch programs that can quickly scale as incentive and compensation methods are optimized while continuing to implement enabling technology in parallel.

Question 2

What, if any, additional information or development on a proposed orchestration framework should be considered before directing the IOUs to file DER orchestration framework applications? What recommendations do parties have regarding any additional work needed and timelines for completing such work, including timing for filing of IOU DER orchestration applications?

SCE believes there should be both the framework envisioned by the Commission as part of the application process, which SCE would refer to as an "end-state framework," as well as a preliminary "development framework" that should be adopted prior to the applications being submitted. The development framework would establish a Commission-guided pathway for the implementation of full-scale DER orchestration through structured, capability-building development activities. This approach allows the Commission, utilities, and stakeholders to learn from real operational experience before making broader decisions regarding permanent program design, technology architecture, compensation, ratemaking treatment, or long-term framework requirements. Please see the Attachment for additional details regarding the contours of such a development framework.

Relatedly, SCE notes that near-term initiation of scalable programs should be integrated into the application schedule. Because learnings regarding customer behavior and compensation will be needed to inform IOU applications for full-scale implementation of DER orchestration, an initial phase of scalable programs should be authorized and initiated before—not after—application development. SCE suggests that Tier 2 advice letters be used to launch near-term scalable programs (including potential funding sources like memorandum accounts), such that when applications are filed, they can build on work already underway.

Based on recent, best-in-class program design and launch activities, it would take the IOUs a minimum of six months to work with Energy Division to design a suite of near-term programs and submit them for approval via Tier 2 Advice Letters, followed by Energy Division review, and further six months to launch any activities after authorization. Seasonality (weather, customer behavior, etc.) may significantly impact the viability and efficacy with which DER orchestration can be used as a reliable alternative to traditional solutions; at least six months of near-term program operations would be needed to cover a suitable range of seasonal impacts. Near-term program results would need to be evaluated, though this evaluation could begin mid-way through program operations. For these reasons, SCE recommends that the application be filed no sooner than nine months after the launch of near-term scalable programs. In total, then, SCE is proposing applications be due no sooner than 21 months from any Decision in Track 2.

Question 3

Given the time required to prepare and decide on potential IOU DER orchestration applications and the related IOU pilots currently underway, how can IOUs: (a) Ensure DER orchestration strategies and implementation stages proposed in future applications incorporate lessons learned, relevant data, and any other benefits generated from the currently ongoing pilots and the information set forth in the record of this proceeding? (b) Coordinate the pilots with the formal DER orchestration application proceeding?

Generally, end-state DER Orchestration applications should institutionalize learning rather than attempt to define a static end-state before the necessary technology, processes, and programs have been tested to determine how best to maximize the benefits of DER orchestration. Scalable programs and other early-stage development activities should become an integral part of the framework-development process. SCE provides responses to the sub-questions below.

(a) Incorporating Learnings from Existing Programs

Either a decision in this Track or the applications themselves should identify learning objectives, establish evaluation criteria, and describe refinement processes.

- Applications should incorporate existing experience from utility programs related to managed charging, orchestration, and customer participation in load management programs, pilots, or demonstrations.

- Learning categories should include technical performance, customer participation and performance, communications, scalability, operational integration, and cost effectiveness.
- Customer-related learnings should include barriers to awareness and enrollment, effectiveness of customer outreach and education, participation and retention, response to incentives, and differences in participation and performance across customer segments.
- When available, evaluation, measurement, and validation (EM&V) program reviews, customer feedback, and lessons learned from existing customer engagement and participation approaches should be considered to identify recurring participation barriers, customer support needs, and customer experience considerations that may inform future DER orchestration strategies and implementation stages.

(b) Coordinating Existing Programs and Applications

Applications should not freeze program design; they should preserve flexibility, innovation, and iterative improvements. To be clear, while some programs, pilots, studies, and demonstrations are underway or completed, several are in the planning stage. SCE proposes that a Tier 2 advice letter be utilized to open new programs and the associated memo account(s) needed to support them.

To coordinate outcomes of development activities with the application proceeding, a common reporting structure should evaluate availability, response accuracy, persistence, customer outcomes, and operational value (see Attachment).

Question 4

What, if any, specific pre-application steps and activities related to DER orchestration, such as convening workshops or a working group process, should be completed prior to the IOUs filing of DER orchestration applications?

SCE recommends a pre-application development phase that combines targeted early-stage development activities (see Attachment) and focused stakeholder workshops. Because DER orchestration is intended to become a dependable grid resource, the utilities need real-world experience with customer participation, operational performance, and planning value to understand how to maximize the value of DER orchestration before being required to propose final framework applications. Applications should build upon demonstrated experience rather than theoretical assumptions.

SCE recommends the CPUC consider the following pre-application steps:

- Conduct targeted customer engagement to inform the development of customer participation approaches. Engagement should focus on understanding customer needs, barriers to participation, the end-user value proposition, and factors that may affect program enrollment and participation continuity.

- Convene focused stakeholder workshops that build upon the conversations started at the May 21st and June 5th workshops. Workshops should focus on a defined set of issues where stakeholder input is needed, rather than attempting to develop all aspects of the DER orchestration framework through a broad stakeholder process.
- Utilize broader stakeholder workshops to report out on development activities and lessons learned as the framework progresses. This provides transparency and allows stakeholder feedback to be considered as the framework is developed.
- Provide an avenue to initiate planned programs, likely through an advice letter process, allowing real-world experiences to inform subsequent framework development.

Question 5

If convening a working group or workshops is warranted, what should be the explicit objectives and key topics to address?

SCE favors focused workshops over an extended working group model. See response to question 4 for details.

Question 6

Parties provided recommendations on regulatory pathways. Please provide feedback on the recommended regulatory pathways or provide alternative proposals.

While SCE initially recommended an advice letter process in lieu of an application process, SCE is now of the opinion that an application process is workable, but must be buttressed by an advice letter process to allow for spin up of development activities in advance of the application to avoid gaps in learning and funding. SCE believes it is important to move expeditiously toward implementation, and that initiating learning activities ahead of framework development is the most effective way to accelerate progress while ensuring the final frameworks are informed by real-world experience. To be clear, it is critical that development activities begin while the applications are being compiled and to continue if necessary while applications are pending review at the Commission.

Question 7

Of the six key discussion topic areas identified during Workshop 1 for developing a DER orchestration framework, which topics or subtopics are best suited for development through stakeholder working groups or future workshops?

SCE supports targeted workshops where stakeholder input is needed such as customer and aggregator participation models.

Question 8

How should the Commission and/or IOUs ensure engagement with California Tribal Nations, environmental social justice communities, and other communities that may be impacted by implementation of the DER orchestration framework that may not be tracking the current proceeding, or have capacity to engage on the highly technical aspects of the proceeding?

SCE supports meaningful engagement including targeted engagement approaches that reflect the needs and circumstances of these communities. Engagement with California Tribal Nations, environmental and social justice communities, and other communities may leverage existing SCE relationships and established community partnerships where appropriate. These existing SCE support channels can help facilitate engagement in accessible, non-technical formats, as appropriate, to ensure the inclusion of the community perspective into program development without the need to participate in highly technical proceedings or workshops.

Question 9

Regarding PG&E's Workshop 1 presentation, when implementing the primary use cases described under Key Topic #1 (system peak reduction, speed to power, and resource-efficient grid investments), are these the correct use cases to implement? If so, which use cases should be implemented first, and which should be implemented in parallel or sequentially?

System peak reduction, speed to power, and resource-efficient grid investments are important use cases for DER orchestration, but each raises different operational, customer, and planning questions. SCE suggests the following refinements:

- DER orchestration efforts should focus on local grid needs, but may also provide system peak reduction benefits in some cases. Regardless, DER orchestration efforts will need to be coordinated with efforts to reduce system peak reduction, including existing demand response, managed charging, and load flexibility programs.
- Speed to power should be pursued early where it can support customer energization needs, and operational requirements are clear; Track 2 should frame it as one orchestration use case without duplicating Track 3 FSC implementation.
- Resource-efficient grid investments are the most complex and require dependable performance, locational certainty, persistence, and forecastability.

SCE is also pursuing real-time reliability use cases such as outage mitigation, congestion management, and load shed avoidance.

Given unique trends across the IOUs in load growth, DER adoption, and grid needs, the IOUs should have the flexibility to develop and prioritize each use case as needed. Rather than

prescribe priority use cases or sequencing, the Commission should establish overarching principles and objectives for DER orchestration while maintaining flexibility for the IOUs to target DER orchestration solutions where they can provide the greatest value.

Question 10

How should the Commission coordinate DER orchestration implementation for IOUs in different stages of technical readiness with regards to telemetry, DER management systems, and other DER orchestration aspects?

SCE appreciates the Commission's interest in encouraging all IOUs to build towards similar capabilities, but given their different circumstances, the three IOUs are necessarily at different points in terms of DERMS maturity, AMI 2.0 rollout, and available telemetry. The Commission should establish common principles and evaluation criteria while allowing utility-specific implementation timelines and architectures based on existing systems and grid conditions, along with geographical/climate and customer characteristics. Taking this customized approach will allow the highest level of readiness while maintaining safety and reliability, and avoid premature lock in of suboptimal solutions.

Question 11

How can current AMI 1.0 and next-generation AMI 2.0 Grid Edge DERMs capabilities support IOU-led DSO DER orchestration programs? (a) What additional communications or technical capabilities are necessary to enable reliable dispatch and settlement of DERs via Grid Edge DERMs? (b) What are differences in capabilities, advantages, and disadvantages of Grid Edge DERMs compared to centralized Enterprise DERMs for enabling IOU-led DSO DER orchestration?

AMI and Grid Edge DERMS can support orchestration, but they should be considered parts of a broader architecture. SCE supports the use of Grid Edge DERMS while clarifying that it does not replace enterprise grid functions.

To set the baseline, AMI 1.0 supports measurement, interval usage visibility, and basic customer load analysis. As proposed in its recent application, SCE's AMI 2.0 would support improved visibility, enhanced communications, customer/device-edge coordination, and improved measurement and verification. Accurate forecasts and measurement of flexible and non-flexible loads is a critical piece of orchestration enabled by AMI 2.0. As presented, Question 11 appears to equate AMI 2.0 with Grid Edge DERMS; however, SCE views these as related but distinct concepts. SCE's AMI 2.0 proposal includes Grid Edge DERMS functionality enabled through the AMI 2.0 platform, including enhanced communications, edge computing capabilities, and coordination of customer-connected devices. However, Grid Edge DERMS represents only one component of the broader AMI 2.0 capability set. Conversely, DER orchestration does not rely solely on Grid Edge DERMS and requires coordination with other systems, including Enterprise DERMS and utility operational systems.

(a) Several elements are required to use Grid Edge DERMS to enable dispatch/settlement of DERs: reliable communications pathways, device interoperability, standardized protocols, cybersecurity protections, and customer authorization/consent mechanisms.

(b) SCE's DER Orchestration vision relies on Enterprise and Grid Edge DERMS working in concert to achieve objectives at different levels of the system hierarchy. As such, a Grid Edge DERMS, without an Enterprise DERMS would fall far short of the capabilities necessary to effectively orchestrate DERs. For example, the utility still must run distribution operations, with operational authority remaining with the DSO and enterprise systems required for system-wide coordination. Enterprise DERMS provides system-wide visibility, distribution constraint identification, operational authority, and portfolio-level dispatch. The reason to layer on Grid Edge DERMS is local execution, and potentially faster device response. It can also serve a parallel role of optimizing the customer premise, or potentially neighborhood load for localized constraints. However, a Grid EDGE DERMS operating without Enterprise DERMS oversight could overload upstream grid elements when managing non-coincident local constraints. In short, Grid Edge DERMS and Enterprise DERMS should be treated as complementary components.

Question 12

What customer-owned DER technologies (e.g., EVs, smart thermostats, water heaters, batteries, other flexible loads) are currently capable of and/or best fits for participating in IOU-led DSO DER orchestration programs to provide value to ratepayers? (a) What technical or operational barriers remain for broader participation?

Each of the DERs listed in the question may be able to participate in IOU-led DER orchestration programs, although all are subject to customer preferences. Batteries are the clearest example of a DER that can provide both customer and grid value in the near term. In addition, certain commercial and industrial loads not listed in the question may prove flexible.

(a) There are technical and operational barriers to broader participation, but also a separate category of economic barriers.

- Technical barriers include availability and interoperability of devices, reliability of the communications backbone, cybersecurity constraints, lack of measurement and verification, and challenges of integration with utility systems.
- Operational barriers take the form of uncertain availability due to customer override behavior, participation fatigue, and changing customer needs.
- Economic barriers include customer equipment costs, absent and/or insufficient incentives (whether compensation or alternative rate design), as well as split or conflicting incentives.

Question 13

What requirements should be established to enable reliable integration of customer-owned DERs into IOU DER orchestration programs? (a) How should IOUs account for customer behavior and resource availability when determining the dependability of orchestrated DERs on the distribution grid?

To enable reliable integration of customer-owned DERs into IOU DER orchestration programs, requirements that demonstrate the reliability, cost-effectiveness, and technical readiness of orchestrated resources must be established. This includes validating through scalable programs how resources, such as demand flexibility, can consistently and sufficiently reduce localized peak loading, and deploying enabling capabilities such as AMI 2.0, and orchestration technologies that support local grid needs.

IOUs should conduct a comprehensive analysis of flexible load populations and customer response, quantify circuit-level impacts, and evaluate load management strategies to determine how they can be deployed effectively at scale. To account for variability in customer participation and resource availability, IOUs may need to adopt an over-enrollment strategy and use validation data from initial programs and granular AMI 2.0 data to determine how resources can be delivered dependably, reliably, and cost-effectively.

Question 14

How should circuit-level demand flexibility be modeled by IOU DSOs to better inform how distribution planning investments should be allocated in future planning cycles?

SCE must analyze real-world outcomes from early DER orchestration programs to determine how much flexibility can reasonably be relied on for load reduction. This requires collecting data on enrolled resource performance so load offset profiles can be built and then applied to planning forecasts to determine if a grid upgrade can be downsized or deferred.

Question 15

In PG&E's opening comments on the Assigned Commissioner's Ruling Issuing Questions on the Electrification Impact Study Part 2 Final Reports, PG&E stated that "the EPIC 4.08 pilot is intended to improve how load flexibility is represented in scenario planning by helping translate flexible load potential into inputs that can be assessed in" distribution system investment plans. What, if any, learnings from PG&E's EPIC 4.08 pilot and its ongoing development can be used to model load flexibility into the annual Distribution Planning and Electrification [sic] Process (DPEP) and how would that be accomplished?

SCE does not have specific insights on PG&E's EPIC 4.08 pilot. Instead, SCE offers general recommendations – the pilot may help clarify how flexible load potential is estimated, how

locational value is assessed, how uncertainty is represented, and how flexibility scenarios compare to traditional infrastructure solutions. Pilot methodologies, however, may not translate directly into program elements applicable to SCE's orchestration needs.

Question 16

The DSO ensures that the system is operated in a safe, reliable manner and is responsible for optimizing system performance. What components are needed for a DER orchestration framework that will ensure these operations continue while also allowing for the flexibility needed to manage load that incorporates a high level of DERs?

It goes without saying that a scalable DER orchestration framework should enable flexibility without compromising the DSO's fundamental responsibility for safe and reliable distribution operations. This requires the following elements to be in place:

- Clear operational authority to identify constraints, define operational needs, and set dispatch parameters
- Appropriate visibility into DERs, whether at the individual or aggregator level
- Technical integration across enterprise, grid edge, customer, aggregator, and OEM devices
- Appropriate and flexible rules for customer and third-party participation, incorporating expectations for reliability, cybersecurity, and performance
- Ability to easily integrate existing or planned programs into program portfolio to enable participation
- Parameters for setting compensation and valuing flexibility
- Performance verification through measurement, event validation, and reporting.
- Ability to curtail or disconnect flexible resources at any time, with or without notice, in the event of an emergency or to correct unsafe operating conditions.

Any orchestration framework must also account for failure, including communications failures, device malfunction, and customer overrides.

Question 17

The IOUs have previously made statements regarding opportunities for lowering costs. Please provide explicit examples of these opportunities including how these opportunities may shift between initial implementation and further scaling.

DER orchestration may create a pathway to cost savings over time, but early programs and initial implementation may include learning and integration costs; therefore, cost-effectiveness should not be the most important factor in the early stages of development and implementation, but should be a target to be reached as the program matures. SCE believes that dependable locational flexibility will allow deferral or avoidance of traditional upgrades,

and customer energization when traditional upgrades are infeasible. This will come through improved utilization of existing infrastructure, particularly where peak demand can be reduced. As programs scale, customer acquisition costs may decline, automation may reduce manual processes, and device interoperability may improve.

There can be other opportunities for lowering costs such as leveraging digital enrollment and standardized marketing (e.g., marketing new programs with existing programs) or shifting customers to more high-value programs. Leveraging existing DERs can reduce device subsidies by using a bring your own technology (BYOT) model (or require customers that accept technology rebates or incentives to required them to participate in a qualified program). Optimize customer incentives based on actual performance rather than a standard amount.

Question 18

Are there any other relevant issues not discussed in the March 23 Assigned Commissioner's Ruling, but brought up in the workshops that the Commission should consider for the DER orchestration application process?

As stated in the introduction to these comments, flexibility-related issues are being addressed across multiple tracks and proceedings. It would be helpful if the Commission could clearly cross-reference other efforts within the scope of each effort. For example, similar issues are being addressed in Track 3 of this proceeding, which in turn draws on similar concepts as the Energization Timelines proceeding. Additional overlap may occur with the Data Working Group proceeding and others implicating DERs. A simple rubric shared between proceedings would go a long way to inform all stakeholders of where specific issues are being addressed. Of particular note, there has been ample discussion of near-term and long-term flexibility – these are profoundly different concepts, as planning decisions require high levels of certainty that short-term customer-driven decisions cannot provide.

SCE also strongly cautions that concepts supported by certain stakeholders, such as open access and statewide markets, should not jeopardize safety and reliability – these goals must be paramount, even if they mean participation is qualified.

SCE also reiterates the fact that scalable programs require time to develop, and that initial funding will be required. The March 23 ACR did not explicitly address these other than a passing mention of pilots – rushing to implement a change as profound as DER orchestration without first properly surveying the field may limit potential benefits and end up failing to deliver from a cost-benefit perspective.

ATTACHMENT

Proposed DER Orchestration Development Framework

Objectives and Expectations

Purpose and Scope (The "Why")

The purpose of the Development Framework is to establish a Commission-guided pathway for the implementation of full-scale DER orchestration through structured, capability-building development activities. The framework should help utilities generate empirical evidence on how DER orchestration can maximize customer value, support location and time-specific grid needs, operate reliably with customers and third parties, and identify the conditions necessary for future scaling. This approach allows the Commission, utilities, and stakeholders to learn from real operational experience before making broader decisions regarding permanent program design, technology architecture, compensation, ratemaking treatment, or long-term framework requirements.

The Development Framework is not intended to decide the permanent program model, operating structure, technology architecture, compensation approach, or ratemaking treatment for DER orchestration. Those end-state decisions should be informed by program results and future Commission review.

Instead, the framework should define the objectives, guardrails, and development areas that early programs should address so that utilities, the Commission, and stakeholders can evaluate results before determining how to incorporate tested approaches into a longer-term orchestration model.

Objectives ("The What")

1. Customer Value: DER Orchestration development activities should generate evidence of a reasonable pathway to reduce the cost of service to all customers if expanded. The early programs should also measure other program outcomes, such as value to participants to assess the likelihood of sustainable enrollment for a permanent program. The framework should provide high-level guidance on the categories of value to be considered, while leaving detailed evaluation methodology, assumptions, and thresholds to program-specific filings; SCE's Evaluation, Measurement & Verification team (EM&V) review; or subsequent Commission consideration. Relevant categories may include:

- Avoided or deferred distribution investment where performance is sufficiently dependable
- Faster energization where flexible load management can help address localized constraints
- Operational flexibility that supports reliable and resilient grid operations

- Direct benefits for participating customers, such as incentives, bill savings, participation options, resiliency, or improved service flexibility
- Potential bulk system, procurement, reliability, resiliency, or GHG-related benefits where relevant to the program use case

Developmental programs should not be required to demonstrate standalone cost-effectiveness, given that development-phase programs may need to invest in learning early on. Rather, they should generate evidence on whether the tested approach could reasonably support customer value if expanded, considering expected benefits, costs, performance, scalability, relevant alternatives, time horizon and other capabilities being vetted through the Development Framework.

2. Technical and Operational Viability: DER orchestration development programs should assess how DERs, flexible loads, enabling technologies, and operational processes can work together to support defined orchestration use cases. The objective is not only to demonstrate technical feasibility, but to determine whether the tested approach can be operated in a manner that supports planning, operational, and energization needs at relevant locations and times. Programs should assess, as applicable:

- Device and DER performance under specific operating conditions
- Multi-device coordination across EVs, storage, HVAC, and other DERs
- Communication and interoperability across utility systems, aggregators, OEMs, and customer devices
- Data availability and measurements needed for performance validation
- Operational processes for identifying, enrolling, dispatching, monitoring and measuring flexible resources
- Aggregator, OEM, and third-party dependability and integration

3. Customer and Market Readiness: DER orchestration depends on customer participation and viable partner models. Programs should define the customer and market conditions that can support durable participation and performance. Programs should assess, if applicable:

- Customer participation and behavioral characteristics
- Customer experience, including enrollment, notifications, and override options
- Aggregator, OEM, and third-party interfaces
- Incentive and compensation structures that enable performance, retention, and customer value

4. Evidence to Support Future Scaling: The Development Framework should help determine the conditions under which DER orchestration will be scaled, including:

- What works and what does not work
- What capabilities are needed for broader deployment

- What evidence can inform future program design, technology needs, compensation, planning treatment, reporting, and cost recovery

Development Program Design Guidelines ("The How")

Program design under the Development Framework should follow a use-case-driven sequence. Each program should (1) begin with a clearly defined grid need, customer opportunity, and/or operational learning objective; (2) identify the resources, customers, locations, systems, and data needed to test that use case; (3) describe how existing and planned capabilities will be leveraged where feasible; and (4) establish the operational guardrails, customer protections, metrics, and reporting needed to evaluate results. Additional details on each of these design features is as follows:

1. Clearly Define the Use Case: Programs should be tied to defined use cases and learning objectives. Potential use cases may include managing localized grid constraints, supporting faster energization, improving operational flexibility, integrating new devices into an orchestration scheme, or enabling new third-party services.

2. Identify Target Resources, Customers, and Locations: Programs should identify the DERs, flexible loads, customer segments, partner models, and locations needed to test the relevant use case. This should include consideration of whether the program is intended to test customer participation, device performance, locational value, operational coordination, or another priority learning area.

3. Use Existing Capabilities and Identify Gaps: Utilities should leverage existing and planned capabilities where appropriate, including DERMs and other management system architecture, advanced metering, aggregator platforms, and related program learnings. Where existing capabilities prove insufficient, programs should identify the incremental capability, data, or process gap being tested.

4. Establish Operational Guardrails and Customer Protections: Programs should preserve utility obligations to operate safely, reliably, and affordably. Utilities should retain sufficient operational visibility and authority to manage grid conditions and address conflicts between distribution needs, customer preferences, partner actions, and other grid signals.

5. Develop Metrics, Reporting, and Course-Correction Criteria: Programs should identify the metrics and reporting needed to evaluate results and inform future decisions. Program design should also identify how results may be used to support continuation, modification, expansion, redesign, pause, or termination.

Development Expectations and Priority Learning Areas (What needs to be tested)

The framework should set structured but flexible expectations for development activities. These expectations should help ensure compatibility and accountability without creating rigid mandates or prescribing a final model. The following areas should

guide development expectations and identify priority learning areas that may cut across planning, operations, customer programs, technology systems, and third-party partners, as applicable.

1. Functional Roles and Systems

- Roles among utility, customers, aggregators, OEMs, grid systems, and market participants
- Systems needed for enrollment, dispatch, measurement, settlement, and reporting

2. Participation Approaches and Customer Experience

- Customer eligibility, enrollment pathway, override rights, retention risks, and partner participation
- Differences in participation by customer segment, device type, and use case
- Customer experience considerations, including enrollment, notifications, controls, incentives, and ongoing engagement

3. Data, Measurement, and Performance Validation

- Data needed to validate dispatch performance, customer response, and grid value
- Measurement limitations that affect whether resources can inform planning, forecasting, or operational decisions
- Performance evidence needed to assess dependability, repeatability, and scalability

4. Cost, Compensation, and Scaling Considerations

- How compensation structures affect participation, performance, retention, and scalability
- How program costs, customer benefits, system benefits, and relevant alternatives should inform future value assessment
- How to avoid duplicative incentives, conflicting signals, or double counting

5. Barriers, Constraints, and Lessons Learned

- Customer experience, vendor readiness, device performance, operational complexity, and cost considerations
- Implementation barriers that should inform future program design or framework refinement
- Lessons that may support continuation, modification, expansion, pause, or termination of the program

Development Program-Specific Implementation Guidelines

General Requirements

Each program should provide enough information for the Commission and stakeholders to understand what is being tested, why it matters, how it will be implemented, how customers and ratepayers will be protected, and how results will inform future decisions. At minimum, each program should identify the problem or opportunity, proposed innovation or advancement, objectives, target resources and customers, budget, timeline, baseline alternative, metrics, customer protections, operational guardrails, and plan for reporting lessons learned. The program should show it is designed to generate evidence rather than resolve major policy issues.

Intent: This section establishes a common structure for program proposals without prescribing a final orchestration model.

Advice Letter Guidelines

Development Program Overview

The Advice Letter should briefly describe the concept, the issue or gap being addressed, the use case being tested, and why the program is appropriate for testing. It should explain whether the program tests a new technology, customer model, partner role, operational process, grid service, compensation approach, or combination of these elements.

Intent: The overview should clarify why the program is needed and how it advances DER orchestration beyond existing or planned programs.

Grid Use Case and Baseline Alternative

The Advice Letter should describe the relevant grid use case, customer opportunity, or operational challenge, including location, timing, magnitude, and duration where available. It should also identify the baseline alternative, such as traditional infrastructure, existing programs, current rates, or a no-action scenario.

Intent: This ensures programs are grounded in measurable needs and can be evaluated against a reasonable alternative, consistent with EE baseline practices and DR load-impact evaluation.

Program Hypothesis and Objectives

The Advice Letter should state the program hypothesis, key learning questions, objectives, and endpoints. Program objectives should fall into the following three areas of exploration: 1) Customer participation, 2) Device / DER Integration & Performance, and 3) Targeting & Dispatch. It should explain why this program is critical for developing at-scale DER Orchestration.

Intent: This converts the program from a general demonstration into a testable learning effort with clear decision points.

Implementation Description

The Advice Letter should describe the resources, customer segments, partners, locations, systems, data flows, enrollment approach, dispatch method, measurement approach, schedule, milestones, dependencies, and risks. It should identify existing capabilities to be used, and any incremental systems, contracts, data, or processes needed.

Intent: This shows whether the program is feasible, appropriately scoped, and capable of producing useful evidence.

Relationship to Existing Authorizations and Proceedings

The Advice Letter should explain how the program relates to existing Commission authorizations, programs, funding sources, and proceedings, including Demand Response, distributed energy resources, rate design, distribution planning, energization, general rate case funding, or other relevant activities. The Advice Letter should identify whether the program relies on existing authorized capabilities, requests incremental program-specific authorization, or overlaps with work being addressed elsewhere.

Intent: This section helps demonstrate that the advice letter pathway will not duplicate existing programs, bypass other proceedings, shift costs improperly, or create conflicts with already-authorized work.

Customer Participation and Protections

The Advice Letter should describe eligibility, enrollment, communications, consent, notifications, override options, incentives, customer support, privacy protections, and safeguards against conflicting program signals or duplicative incentives.

Intent: DER orchestration depends on durable customer participation and trust. This section ensures programs assess customer experience and protect customers while testing resource dependability.

Cost-Benefit Methodology

The Advice Letter should explain how programs will provide relevant information on costs and benefits for different DER orchestration program designs, including cost categories, value streams, baseline assumptions, avoided costs, customer impacts, and qualitative benefits where relevant. Early programs should not be required to be cost-effective but should explain how the evidence will inform future program designs that maximize DER orchestration value.

Intent: This creates accountability for value while recognizing that early programs are intended to generate evidence, not prove an end-state model.

Budget

The Advice Letter should identify the budget, cost categories, and duration. It should distinguish foundational capabilities from incremental program-specific costs.

Intent: This provides explanation of budgets sufficiently to communicate and demonstrate program effectiveness.

Reporting Plan

The Advice Letter should identify the reporting cadence, data sources, evaluation approach, expenditure tracking, lessons learned, and closeout process. Results should inform whether the program should continue, be modified, expanded, redesigned, paused, or terminated.

Intent: This ensures programs produce transparent, comparable, and decision-useful evidence.

Procedural Notice and Stakeholder Review

The Advice Letter should identify the notice and stakeholder review process that will apply to the program, including service on relevant proceeding service lists, notice to affected stakeholders, and an opportunity for comment consistent with the applicable advice letter process. The Advice Letter should also identify how stakeholder input will be considered before implementation, modification, expansion, or closeout.

Intent: This section supports procedural fairness and transparency, making advice letter review more defensible by preserving notice, participation, and stakeholder oversight without requiring a full application for every program.

Recommended Program Descriptions

Functional Roles and Interfaces

Each Advice Letter should identify the roles of the utility, customers, aggregators, OEMs, implementers, technology providers, and other parties, including responsibility for enrollment, dispatch, communications, data exchange, measurement, settlement, reporting, and issue resolution.

Intent: Clear roles reduce implementation risk and support operational accountability.

Participation Approach

Each Advice Letter should describe the participation model, eligibility, enrollment path, customer obligations, incentives, override rights, retention strategy, and expected customer experience. Explain the scalability of this approach, if this is an applicable intention of the program.

Intent: This ensures the program tests whether the participation model can support reliable and scalable performance.

Data Flows and Data Requirements

Each Advice Letter should identify the data needed for eligibility, enrollment, dispatch, monitoring, measurement, verification, customer support, reporting, and evaluation, along with how data will be collected, validated, protected, and used.

Intent: Reliable data is necessary to determine whether program results can support planning, operations, and future scaling.

Communications and Integration Approach

Each Advice Letter should describe the dispatch pathway, timing of signals, communications standards, integration requirements, testing approach, and cybersecurity considerations.

Intent: DER orchestration requires dependable communications and integration across customer devices, third parties, and utility systems.

Key Constraints and Limitations

Each Advice Letter should identify known risks and limitations, including customer recruitment, vendor readiness, device availability, data quality, communications latency, operational constraints, funding limits, and scalability barriers.

Intent: Identifying constraints upfront helps stakeholders interpret program results and distinguish design issues from broader market or technology barriers.

Program Metrics

Technical Performance Metrics

Metrics may include dispatch success, response magnitude, timing, ramp rate, duration, persistence, availability, telemetry quality, communications success, device performance, coordination performance, and failure rates.

Intent: These metrics test whether resources can deliver the physical response needed for the program use case.

Customer and Participation Metrics

Metrics may include eligible customers, enrolled customers, active participants, enrollment conversion, retention, opt-outs, overrides, satisfaction, complaints, support needs, incentive acceptance, and participation by segment.

Intent: These metrics test whether customers will participate in a durable and scalable way.

Grid Services Performance Metrics

Metrics may include load reduction, load shift, flexible capacity delivered, local constraint mitigation, energization support, peak reduction, operational flexibility, reliability support, and avoided or deferred upgrade potential.

Intent: These metrics connect program performance to grid value.

Cost/Benefit and other Economic Metrics

Metrics may include total cost, cost per customer, cost per device, cost per kW or kWh delivered, incentive costs, vendor costs, administrative costs, measurement costs, estimated avoided costs, customer impacts, and relevant qualitative benefits.

Intent: These metrics help determine whether the program has a reasonable pathway to customer and system cost-effectiveness if expanded.

Readiness and Scaling Metrics

Metrics may include whether endpoints were met, processes were repeatable, systems and data were sufficient, partners performed reliably, customers remained engaged, costs appear scalable, and additional regulatory or operational changes are needed.

Intent: These metrics support decisions on continuation, modification, expansion, redesign, pause, or termination.

Modifying and expanding Programs

Criteria for Program Modification

A program may be modified when interim results show that changes are needed to improve learning, protect customers, address implementation barriers, refine incentives, adjust technologies, improve data collection, extend timeline, or resolve operational issues.

Intent: This allows programs to adapt while maintaining accountability.

Criteria for Program Expansion and Scale-Up

A program may be expanded when results indicate that the tested approach is technically feasible, operationally manageable, customer-acceptable, measurable, partner-supported, and likely to provide value at larger scale.

Intent: This creates a disciplined path from early program learning to testing broader deployment.

Criteria for Redesign, Pause, or Termination

A program should be redesigned, paused, or terminated if it is unlikely to produce useful evidence, customer protections are insufficient, costs materially exceed expectations, performance is inadequate, data is insufficient, or continuation creates unreasonable operational or ratepayer risk.

Intent: This protects customers and ratepayers while preserving useful lessons.