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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

ASSIGNED COMMISSIONER'S RULING ON TRACK 1 AND TRACK 2 DISTRIBUTED ENERGY RESOURCES ORCHESTRATION

This Ruling sets an April 29, 2026 workshop to discuss options for Track 2 of Rulemaking 21-06-017 focusing on the development of a distributed energy resources (DER) orchestration framework for investor-owned utility (IOU) Distribution System Operators (DSOs). The Ruling presents an approach for moving forward with development of a framework for DER orchestration for IOU DSOs. The ruling proposes that Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), collectively referred to as the Investor-Owned Utilities (IOUs), would file applications for the development of an IOU DSO-led DER orchestration framework for each respective IOU. Finally, this Ruling directs parties to respond by April 13, 2026, to questions on the proposed IOU DSO-led DER orchestration application process as well as Transmission System Operator (TSO)-DSO coordination workshops, the cadence of Integrated Capacity Analysis (ICA) workshops, and the filing of Grid Modernization Reports (GMRs). Reply comments are due by April 20, 2026.

1. Background

The Commission launched Rulemaking (R.) 21-06-017 to study the impacts of high penetrations of DERs on the grid, identify better forecasting strategies,

and plan and operate a distribution system that can support a large number of distributed energy resources on the grid in the future, i.e., a "High DER Future." Track 2 of this proceeding focuses on the IOU DSOs.

The August 11, 2023 Assigned Commissioner's Amended Scoping Memo and Ruling (Amended Scoping Memo) laid out the following two issues for Track 2: (1) What are the operational needs necessary to efficiently operate a high DER grid and unlock economic opportunities for DERs to provide grid services, limit market power, reduce ratepayer costs, increase equity, support grid resiliency, and meet State policy objectives; and (2) What are the existing gaps and barriers in achieving the needs identified above within our current IOU-operated Distribution System Operator? What are the potential solutions in overcoming these barriers?

The Amended Scoping Memo adopted a schedule that included a Future Grid Distribution System Operation workshop series followed by a workshop report and a proposed decision. The Commission's consultant, Gridworks, hosted three public workshops and developed a workshop report referred to as the Future Grid Study Report (FGS Report).

The FGS Report was the culmination of the three workshops facilitated by Gridworks during the first half of 2024. The workshops provided parties and other stakeholders an opportunity to collaborate on ideas for modernizing the electric grid for a future with a high number of DERs on the California electric grid. The FGS Report offered a comprehensive account of the three workshop topics: (1) distribution system operational needs to enable a "High DER Future"; (2) the gaps between current distribution system operational capabilities and identified operational needs; and (3) a set of recommendations to address the

identified gaps. The FGS Report provided details on the ten broad categories of operational needs identified by workshop participants.

1. DER visibility to the DSO
2. DER visibility to the California Independent System Operator (CAISO)
3. DER dispatchability/control
4. Operational planning and analysis
5. Reliability coordination at transmission-distribution interface
6. DER technical performance standards
7. Cybersecurity
8. Open access to distribution system
9. Layered system architecture from bottom-up
10. Animate distribution-level markets/granular pricing

Based on the record of the proceeding, including the FGS Report, the proposal set out in this ruling identifies five priority areas to guide the focus of the Track 2 DER Orchestration Framework.

- DER Visibility to DSO
- DER Visibility to CAISO
- DER dispatchability/control
- Open access to distribution system
- Reliability coordination at Transmission-Distribution (T&D) interface

Rather than develop separate options related to each of the five priority DSO operational needs, a more holistic framework that integrates elements of all five operational needs is proposed. The DER Orchestration Framework aims to enable the IOUs to leverage the flexibility of DERs to provide critical grid

services, including reliability support, outage mitigation, infrastructure deferral, and facilitating energization for electrification.

2. Proposed DER Orchestration Framework

According to the record developed in Track 2, DER Orchestration is the coordinated management of DERs by a DSO. Using visibility, forecasting, and control/scheduling tools, DSOs identify location- and time-specific distribution needs and signal eligible DERs (directly or via aggregators) to deliver verifiable services that align with those needs. PG&E and SCE describe orchestration as the centralized analysis of grid conditions and the dispatch of DERs to provide additional distribution-level services, such as reliability support, voltage management, and deferral infrastructure, all while ensuring "open access" so the customer and aggregators can understand how to participate.[1]

This perspective positions orchestration as a DSO grid-operations function that both enables DERs to deliver distribution-level services and allows transparent participation pathways. DER orchestration, when implemented through a DSO framework, refers to the coordinated management of technologies such as solar, batteries, electric vehicles, and flexible loads across the distribution grid. Under this model, the utility uses real-time data, DER visibility, forecasting, and control signals or scheduling tools to balance supply and demand, mitigate constraints, and enable DERs to deliver additional grid services in a measurable way with cost containment guardrails. This approach could support both operational reliability and long-term decarbonization goals. As stated in SCE and PG&E's joint comments:

> When the Joint [Investor-Owned Utilities] refer to DER orchestration, that does not mean the DSO controls every DER

[1] PG&E and SCE Joint Parties Opening Comments on the Future Grid Study at 2.

> at all times. Instead, it means that the DSO must understand where DER services are beneficial to the grid and then send appropriate signals to the DERs, such as schedule and dispatch, or alternatively price data if a DER is enrolled in a pricing program, so that those services are more fully aligned with the distribution system needs. The orchestration function must understand the heterogeneous resources downstream of a specific grid need to send the appropriate signal to DER resources that can adequately meet the needed duration and magnitude, as well as build contingency resources for reliability.[2]

DER orchestration aims to create efficiency by increasing capacity utilization, avoiding capacity upgrades, and unlocking operational efficiencies. If successful, DER orchestration may contribute to ratepayer cost reductions once operational.

2.1. Initiation of DER Orchestration

The following sets out initial first steps for a framework for IOU DER orchestration:

- Develop models for cost-effective grid services and evaluate the benefits and challenges of different models and use cases.
- Advance open, interoperable communication for DSO DER visibility and behind-the-meter DER grid services.
- Enable DER visibility to CAISO and DSO–CAISO coordination.
- Evaluate options for compensating distribution flexibility procurement/dispatch mechanisms.
- Define performance metrics and evaluation criteria.
- Identify appropriate initial locations on the system.

This ruling proposes a hybrid procedural approach that begins with two Commission-led workshops to build early alignment on key technical,

[2] PG&E and SCE Joint Parties Opening Comments on the Future Grid Study at 10.

conceptual and market issues, followed by formal applications from the IOUs to develop and operationalize the full DER orchestration framework.

The first commission-led workshop will refine the proposed application process, including discussion of guiding principles, technical requirements, and other foundational elements necessary for DER orchestration. The intent for the workshops is to gather stakeholder input, clarify areas of alignment, and identify issues requiring further development. The applications that could follow a proposed decision in Track 2 of this proceeding could include Commission review of cost recovery proposals, defining initial implementation (e.g., where, when, and how), and scalability plans.

Issues that could be discussed in Workshop 1 and in party comments include the application process, which could include proposals for additional workshops and potentially a new working group focused on review of framework implementation and related matters. This approach could provide a more in-depth review through a formal application process and leverage early IOU and stakeholder engagement and build consensus among parties while providing comprehensive, utility-specific proposals for consideration within a structured regulatory process.

The second commission-led workshop will focus on enabling DER visibility to CAISO and coordination between DSOs and CAISO. Additional information on this workshop can be referenced in Section 4 of this ruling.

3. IOU DSO-led DER Orchestration Initiation

Below are a set of questions regarding the process for implementation of the DER Orchestration Framework and proposed application process. Responses to these questions should be as detailed and complete as possible.

1) What should some of the primary objectives of IOU DSO-led DER orchestration be?
2) What are the primary grid constraints that could be solved, or operational improvements that could be created, through implementation of a utility DSO-led DER orchestration?
3) What are appropriate valuation frameworks to quantify ratepayer value to potentially be unlocked through DER orchestration?
4) Should the Commission adopt the following set of guiding principles to shape the proposed IOUs' DER orchestration framework applications?
    - Ratepayer benefit and protection
    - Technology-neutral, performance-based
    - Locational and temporal value recognition
    - Efficient operation of the grid
    - Open access and Interoperability
    - Transparent participation pathways and compensation
    - Incremental, evidence-based implementation
    - Equity and customer protection
    - Cyber-secure and resilient
    - Preventing double compensation

Should the Commission remove, modify, or clarify any of these guiding principles? Should the Commission add additional guiding principles? If the Commission adopts these guiding principles, should there be an opportunity to refine them in any proceeding reviewing IOU applications?

5) How can findings from the Electrification Impact Study Part 2 (EIS Part 2) conducted as part of Track 1 of this proceeding inform the DER Orchestration application content? For example, can findings from EIS Part 2 inform the identification of areas best suited for piloting DER orchestration?
    a. Should the IOUs consider the results from the EIS Part 2 studies to phase implementation of DER Orchestration? If so, how should the results from the equity and enhanced demand flexibility scenarios in the EIS Part 2 studies be considered?
    b. Should the IOUs include examples based on the equity and enhanced demand flexibility scenarios in their proposed applications?
6) Should the IOUs include a proposed shared savings mechanism (SSM)[3] for successfully implementing DER Orchestration as part of the proposed application?
7) Should the IOUs include a review of the DSO incentive structures from regulators of other jurisdictions such as the United Kingdom (Ofgem) and Australia for discussion in stakeholder workshops?
8) Should the proposed applications address scaling and IOU readiness and the role of Advanced Distribution Management Systems/Distributed Energy Resources Management Systems (ADMS/DERMS)?
9) How should the proposed applications demonstrate IOU readiness to implement DER orchestration? How should the Commission reconcile different states of readiness of each utility so that meaningful progress can be made?
10) Should the IOUs present their proposed strategy for achieving interoperability, including communications protocols, to enable scalable DER orchestration?

[3] A shared savings mechanism (SSM) is an incentive structure that allows utilities to share in the net cost savings generated by DER solutions that reduce the need for traditional, more expensive grid infrastructure investments.

11) Should the proposed DER Orchestration applications include a proposed phased implementation and deployment plan? If so, what elements should the plan contain?

12) What potential cost-effective mechanisms or measures could be included as part of the proposed DER orchestration framework to demonstrate a net benefit to ratepayers?

13) What potential benefit-cost methodology could these applications use?

14) How can IOU DSO-led DER Orchestration implementation be complementary and compatible with the potential rollout of real-time pricing?

15) How should the proposed DER Orchestration applications address the role and participation of DER aggregators within the proposed framework on issues such as coordination with the DSO, performance standards, data exchange requirements, and metrics to address accountability mechanisms?

16) Should the proposed DER Orchestration applications identify additional technology investments required to support DER orchestration implementation (e.g., DERMS enhancements, communications infrastructure, device-level controls)?

17) Should the proposed DER Orchestration applications request details on whether the above mentioned technological capabilities should be customer-owned or utility-owned and what the estimated costs are?

4. Enabling DER Visibility to the CAISO and Coordination Between DSOs and CAISO

4.1. Background

The CAISO oversees the operation of the bulk electric system for the CAISO balancing authority area. In conjunction with the Commission and other load-serving entities, the CAISO is responsible for ensuring sufficient electric

supply is available to meet demand. As DER adoption accelerates, CAISO's visibility into emerging resources - such as behind-the-meter (BTM) batteries, electric vehicles (EVs), and residential load controls - remains limited. DER visibility is important to help the CAISO understand how each type of DER can impact CAISO load. This lack of visibility presents challenges to the CAISO's processes for forecasting load, managing grid reliability, and ensuring efficient system operations. To address these gaps, CAISO emphasizes the need for improved coordination and data sharing with DSOs to support coordination between transmission and distribution system operations.[4] The high-level goals of DSO-CAISO coordination include:

- Enhance CAISO DER visibility by improving access to aggregated data on DER capacity, schedules, and performance to support accurate forecasting, market efficiency, and system reliability.
- Strengthen TSO-DSO coordination by clarifying roles, responsibilities, and data-sharing protocols so that DERMS development aligns with CAISO's operational needs.
- Facilitate collaboration between TSOs, DSOs, and stakeholders on shared priorities for DER integration and grid operations through Commission-sponsored workshops.

4.2. TSO-DSO Coordination Workshop Scope and Objectives

The Commission, in collaboration with CAISO, will hold a workshop to align TSOs, DSOs, and stakeholders on shared priorities for DER integration and grid operations under a high-DER future. The workshop will aim to address how IOUs can meet CAISO's DER data needs (e.g., DER capacity, location, schedule, performance data, and location) while addressing data-sharing feasibility,

[4] CAISO, Opening Comments to R2106017 (Future Grid Study), 2024 at 1-6.

existing DERMS capabilities, and any technical or privacy constraints. The workshop will focus on ensuring reliable coordination at the transmission-distribution interface by addressing how DERMS development aligns with CAISO's forecasting, market operation and reliability requirements, and propose mechanisms for coordination and minimum viable data exchange. Below is a set of questions regarding the objective and scope of a jointly coordinated TSO-DSO workshop. Parties are encouraged to be as detailed and complete as possible in their responses.

What issues should be addressed in the TSO-DSO workshop related to DER visibility and coordination under a DER orchestration framework?

Should operational requirements and wholesale market participation be considered?

5. Cadence of Integrated Capacity Analysis Workshops

D.24-10-030 ordered the consolidation of all ICA reporting into biannual reports as well as IOU submission of Tier 3 advice letters containing remediation plans for all known ICA issues.[5] D.24-10-030 also ordered the IOUs to hold quarterly workshops to accompany the reports and remediation plans.[6] The IOUs currently file their biannual reports at the end of each January and July, and the quarterly workshops are held at the end of each quarter. The first workshop was held on March 7, 2025.

With the submission of the ICA remediation plans in August 2025, there may be less of a need for IOUs to hold quarterly workshops. Instead, a biannual cadence could be more aligned with the release schedule of the biannual reports

[5] D.24-10-030 Ordering Paragraph (OP) 34 and 36.

[6] D.24-10-030 OP 35.

and allow more progress to be made by the IOUs on their remediation plans between workshops. Additionally, IOUs could file Tier 2 advice letters to change the frequency of future workshops to conform with the evolving rhythm of ICA planning. D.24-10-030 currently requires the IOUs to hold ICA workshops quarterly until sixty days after the fourth anniversary of the first workshop, at which point the IOUs may submit a Tier 3 advice letter proposing to extend or sunset the workshop series.[7]

Below is a set of questions regarding possible changes to the cadence of ICA workshops. Parties are encouraged to be as detailed and complete as possible in their responses.

Should the ICA quarterly workshop requirement be reduced to biannual, aligning with the release of the biannual ICA reports?

Should the IOUs be authorized to submit a joint Tier 2 advice letter to propose modifications to the frequency of the ICA workshops?

6. Grid Modernization Reports

Assembly Bill (AB) 242 (Stats. 2019, Chap. 418) amended Public Utilities (Pub. Util.) Code Section 913.6 to create a new Grid Modernization Report requiring the Commission, in consultation with the CAISO and the California Energy Commission (CEC), to biennially report to the Legislature and the Governor on the progress made toward modernizing the state's distribution and transmission grid and the impacts of DERs on the state's distribution and transmission grid and ratepayers. California's *Grid Modernization Report to the Governor and Legislature* is published February 1 in odd years. The next report is due to be published by February 1, 2027.

[7] D.24-10-030 OP 35.

D.18-03-023 provides a framework for Grid Modernization and requires the IOUs to submit their 10-year vision for modernizing the grid when filing their General Rate Case. The CPUC adopted the following definition of grid modernization in D.18-03-023:

> A modern grid allows for the integration of distributed energy resources (DERs) while maintaining and improving safety and reliability. A modern grid facilitates the efficient integration of DERs into all stages of distribution system planning and operations to fully utilize the capabilities that the resources offer, without undue cost or delay, allowing markets and customers to more fully realize the value of the resources, to the extent cost-effective to ratepayers, while ensuring equitable access to the benefits of DERs. A modern grid achieves safety and reliability through technology innovation, to the extent that is cost-effective to ratepayers relative to other legacy investments of a less modern character.[8]

To support the production of the legislative report, the Energy Division issued a data request to the utilities to gather updates on their grid modernization progress. The resulting updates were included as part of the 2025 legislative report.[9]

Below is a set of questions regarding the filing of grid modernization reports. Parties are encouraged to be as detailed and complete as possible in their responses.

1. Should the Commission require the IOUs to submit their Biennial Grid Modernization Progress Reports in the fall of even-numbered years (e.g., 2026, 2028) to align with reporting requirements under Pub. Util. Code Section 913.6?

[8] D.18-03-023 at 7.

[9] The 2025 *California's Grid Modernization Report to the Governor and Legislature* is found here: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2025/californias-grid-modernization-report-2025--volume-i.pdf

2. Should the Commission adopt the proposed Appendix A as the standardized format and content requirements for IOU's biennial grid modernization update?
3. What additional information, if any, should be included in the reporting requirements?
4. What information, if any, should be omitted from the reporting requirements?
5. Should the Commission establish a sunset or review date for Appendix A reporting requirements to ensure alignment with the evolving grid modernization technology and goals?
6. Should the Commission require the utilities to use a Tier 1 or Tier 2 advice letter or other process to propose modifications to their grid modernization reporting approach or content?
7. Should the Commission authorize the Energy Division to direct changes to the content and format of the reporting approach?

7. Conclusion

1. Parties are directed to file comments responding to the questions included in this ruling by April 13, 2026, with reply comments due by April 20, 2026.

2. An Energy Division staff-led workshop on the proposed IOU DER orchestration framework application process will be held on April 29, 2026. An agenda will be shared prior to the workshop.

3. Parties wishing to provide presentations on the questions presented in the ruling or a subset of the questions shall provide presentation materials by serving the service list to this proceeding no later than April 22, 2026. Presentation materials will be incorporated into the proceeding record.

IT IS SO RULED

Dated March 23, 2026, at San Francisco, California.

/s/ DARCIE L HOUCK

Darcie L. Houck
Commissioner

Appendix A

I. Introduction

a. Overview of Grid Mod Plan and related background information

II. Grid Modernization Activities (Past Two Years)

a. Grid Management Systems (e.g., ADMS, DERMS, etc.)

- Description and status (e.g., completed, in progress, deployed)
- Key milestones achieved, including timelines
- Benefits realized and current use cases
- Challenges encountered and any modifications to the original plan
- Planned future use cases and anticipated benefits
- Costs incurred and anticipated

b. Communications and Cybersecurity Infrastructure

- Description and status (e.g., completed, in progress, deployed)
- Key milestones achieved, including timelines
- Benefits realized and current use cases
- Challenges encountered and any modifications to the original plan
- Planned future use cases and anticipated benefits
- Costs incurred and anticipated

c. Engineering Software and Planning Tools

- Description and current status (e.g., completed, in progress, deployed)
- Key milestones achieved, including timelines
- Benefits realized and current use cases

- Challenges encountered and any modifications to the original plan
- Planned future use cases and anticipated benefits
- Costs incurred and anticipated

d. Advanced Metering Infrastructure (AMI) and Grid Edge Computing Applications

- Description and status (e.g., completed, in progress, deployed)
- Key milestones achieved, including timelines
- Benefits realized and current use cases
- Challenges encountered and any modifications to the original plan
- Planned future use cases and anticipated benefits
- Costs incurred and anticipated

e. Other relevant technologies and topics

III. Conclusion

a. Summary of key findings and progress

b. Forward-looking outlook and next steps