

FILED
07/27/26
04:59 PM
R2106017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) OPENING COMMENTS ON THE ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S RULING ISSUING QUESTIONS ON THE DISTRIBUTED ENERGY RESOURCES ORCHESTRATION WORKSHOP REPORTS

BENJAMIN C. ELLIS

Pacific Gas and Electric Company
300 Lakeside Drive, Suite 210
Oakland, CA 94612
Telephone: (415) 265-2678
E-Mail: Ben.Ellis@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: July 27, 2026

TABLE OF CONTENTS

Page

I. INTRODUCTION 1

II. PG&E'S RESPONSES TO RULING QUESTIONS 2

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? 2

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? 2

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: 7

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? 7

b. Coordinate the pilots with the formal DER Orchestration Application Proceeding? 7

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? 7

5. If convening a working group or workshops is warranted, what should be the explicit objectives and key topics to address? 7

6. Parties provided recommendations on regulatory pathways. Please provide feedback on the recommended regulatory pathways or provide alternative proposals. 7

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? 8

TABLE OF CONTENTS
(continued)

Page

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? 9

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? 10

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? 11

11. How can current AMI 1.0 and Next-Generation AMI 2.0 Grid Edge DERMS capabilities support IOU-led DSO DER Orchestration programs? 12

    a. What additional communications or technical capabilities are necessary to enable reliable dispatch and settlement of DERS via grid edge DERMS? 12

    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? 13

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? 14

    a. What technical or operational barriers remain for broader participation? 15

13. What requirements should be established to enable reliable integration of customer-owned DERs into IOU DER orchestration programs? 16

    a. How should IOUs account for customer behavior and resource availability when determining the dependability of orchestrated DERs on the distribution grid? 16

TABLE OF CONTENTS
(continued)

Page

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? 17

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.1 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 Process (DPEP) and how would that be accomplished? 18

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? 19

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. 20

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? 21

III. CONCLUSION 21

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) OPENING COMMENTS ON THE ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S RULING ISSUING QUESTIONS ON THE DISTRIBUTED ENERGY RESOURCES ORCHESTRATION WORKSHOP REPORTS

Pursuant to the *Assigned Commissioner and Administrative Law Judge's Ruling Issuing Questions on the Distributed Energy Resources Orchestration Workshop Reports* (Ruling), filed July 9, 2026, Pacific Gas and Electric Company (PG&E) provides its opening comments on the questions posed in the Ruling.

I. INTRODUCTION

PG&E supports the continued development of Distributed Energy Resources (DER) orchestration to advance affordability, support electrification, and enhance the reliability of the distribution system. At this stage, the Commission should establish foundational principles, implementation guardrails, funding pathways, and reporting and governance standards, while avoiding premature adoption of a comprehensive end-state framework before sufficient operational experience has been developed.

PG&E recommends an iterative, evidence-based approach that allows targeted DER orchestration demonstrations to proceed through an expedited regulatory pathway, such as a Tier 2 Advice Letter or comparable Commission-approved process. Demonstrations should be tied to identified or emerging grid needs, including overload mitigation, speed-to-power applications, flexible interconnections, managed electrification, and infrastructure deferral opportunities. Standardized reporting, annual stakeholder workshops, and synthesis reports should inform Commission and stakeholder evaluation of pilot results, lessons learned, readiness to scale, and any refinements needed before broader DER orchestration applications are required.

PG&E further recommends that the framework remain technology-neutral, capability-based, and flexible enough to accommodate multiple participation models, including utility-managed programs, aggregator-managed resources, market-based approaches, and customer-responsive technologies. The framework should ensure dependable performance, interoperability, measurement and verification, and appropriate treatment of customer behavior and resource availability.

II. PG&E'S RESPONSES TO RULING QUESTIONS

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?

PG&E does not have any additional comments to the workshop reports.

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?

DER orchestration has the potential to improve affordability, accelerate electrification, enhance reliability, and defer or avoid infrastructure investments. Generally, DER orchestration has the potential to improve affordability, accelerate electrification, enhance reliability, and defer or avoid infrastructure investments. The Commission should therefore continue advancing DER orchestration while establishing a limited set of foundational framework elements. While additional development is warranted in certain areas, implementation activities should not be delayed pending resolution of every outstanding policy, operational, and market design question.

Workshop participants identified several areas where additional experience and stakeholder input would improve understanding of the optimal operational, technical, and market structures for DER orchestration. First, rather than delaying implementation until all outstanding policy questions have been resolved, the Commission should establish core guardrails and enable a pathway for targeted demonstration activities designed to generate operational experience. Demonstration activities should focus on specific, emerging grid needs and use cases rather than

testing DER orchestration as a generalized concept. Prioritizing demonstrations around actual system needs, such as overload mitigation, flexible interconnections, electrification support, and infrastructure deferral opportunities, will maximize learning while providing the greatest opportunity to evaluate ratepayer value. Real-world demonstrations will provide valuable insights regarding DER visibility requirements, dispatch performance, interoperability, customer behavior, measurement and verification approaches, and interactions between utilities and third-party providers. The Commission can then use these findings to inform subsequent implementation decisions and framework refinements. An iterative approach grounded in observed outcomes is more likely to produce cost-effective and durable solutions than attempting to prescribe a comprehensive end-state model in advance of practical experience.

Second, priority areas for additional development before IOUs file DER orchestration framework applications include:

- **Formalize DSO-Orchestration Principles**

The Commission should finalize a common set of guiding principles that can be applied consistently across all utilities, including:

  - Ratepayer affordability and net benefits, including preventing new or additional cost shift for non-participating customers, as proposed by PG&E in its response to the Assigned Commissioner's Proposal on Flexible Connections in the High-DER Track 3.
  - Open access and interoperability
  - Technology neutrality
  - Transparency and customer protections
  - Cybersecurity and data privacy
  - Prevention of double compensation
  - Planning-grade performance requirements
  - Competitive neutrality and appropriate oversight mechanisms

Several parties identified these principles as necessary to evaluate future applications and ensure consistency across service territories.

- **Establish Process for the IOUs to Request Funding**

The Commission should establish a streamlined process through which an IOU may request authorization and funding for DER orchestration demonstration activities designed to address specific, identified or emerging grid needs, which may include increasing capacity capabilities. Demonstration proposals should be submitted through an expedited Advice Letter (Tier 2) or similar Commission-approved process, with funding authorized through a dedicated balancing account. A Tier 2 Advice Letter process provides an appropriate balance between regulatory oversight and implementation flexibility, allowing the Commission to review and approve targeted demonstration activities while enabling utilities to incorporate lessons learned and adapt future activities based on empirical results and demonstrated ratepayer value. The Tier 2 Advice Letter should clearly identify: (1) the emerging grid need to be addressed; (2) the geographic area and use case under evaluation; (3) the proposed DER orchestration approach; (4) the expected benefits relative to traditional utility solutions; (5) the technical and administrative budget to enable and measure the proposed use case and demonstration that this funding is not duplicative of funding from other sources (e.g. GRC) (6) key performance metrics; and (7) customer protection, cybersecurity, and data-governance measures. Demonstrations should be tied to actual distribution-system needs, such as capacity constraints, overload mitigation, managed electrification growth, flexible interconnection opportunities, or infrastructure deferral opportunities identified through utility planning and operational processes. This framework would allow the Commission to maintain oversight while providing utilities sufficient flexibility to test and evaluate emerging orchestration approaches in a timely manner.

- **Develop Reporting and Governance Framework**

PG&E proposes the following reporting, governance, and learning *process*pProcesses:

  - **Annual IOU Pilot Reporting**

Each utility should provide standardized annual reports describing ongoing demonstration and pilot activities. Reports could include:

- Pilot objectives and use cases
- Locations and emerging grid needs being addressed
- Participating technologies and DER types
- Customer enrollment and participation metrics
- Dispatch frequency and performance
- Operational observations and lessons learned
- Technology and communications performance
- Cost and benefit metrics, to the extent available
- Readiness to scale criteria such as:
    - ADMS capabilities
    - DERMS maturity
    - Forecasting capabilities
    - Dispatch capabilities
    - Measurement and verification processes
    - Cybersecurity controls
    - Operational procedures

Reports should also identify lessons learned (both successful and unsuccessful outcomes), as well as stakeholder feedback, suggestions, and corrective actions to ensure the Commission and stakeholders gain a complete understanding of implementation realities.

- **Annual Stakeholder Workshops**

The Commission could convene annual workshops where utilities present pilot results and stakeholders have an opportunity to discuss findings. These workshops would be used to:

- Share lessons learned from demonstrations and pilots
- Compare experiences across utility territories
- Promote transparency regarding pilot objectives, design, and results
- Identify common implementation challenges and lessons learned
- Discuss emerging best practices
- Develop recommendations regarding framework refinements
- Provide a forum for discussing emerging issues related to interoperability, valuation, customer participation, measurement and verification, and operational readiness

- Evaluate whether additional policy guidance is needed.

This process would help ensure that stakeholders remain informed while avoiding the delays associated with formal application proceedings for every incremental learning activity.

- **Annual Synthesis Report**

On an annual basis, the working group or Energy Division could develop a synthesis report identifying:

- Key lessons learned across DSOs
- Areas of stakeholder alignment
- Outstanding policy questions
- Recommended framework refinements
- Recommended updates to evaluation metrics
- Recommended updates to interoperability and data-sharing requirements
- Recommended next-phase demonstration activities

This report would establish an evolving evidentiary foundation for future Commission decisions.

As stated previously, parties should not delay implementation activities pending resolution of every framework issue, nor should the Commission require comprehensive DER orchestration applications before sufficient operational experience exists. Instead, the Commission should establish foundational principles, reporting requirements, readiness criteria, and customer protections in the near term; authorize targeted demonstration activities through an expedited approval process; and leverage the resulting operational experience to inform subsequent DER orchestration applications. The primary purpose of demonstration activities is not merely to pilot and test technologies, but to develop the operational, planning, valuation, and governance experience necessary to inform a scalable DER orchestration framework.

This phased, evidence-based approach will enable the Commission to advance DER orchestration in a manner that promotes innovation, protects ratepayers, and grounds future framework decisions in demonstrated performance.

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?

The proposed "Annual IOU Pilots Report" and "Annual Stakeholder Workshop," as described in the response to Question 2, will provide the forum for IOUs to report on lessons learned, data, and benefits from the pilots.

b. Coordinate the pilots with the formal DER Orchestration Application Proceeding**?**

The proposal set forth in PG&E's response to Q2 under "Proposed Reporting, Governance, and Learning Process" outlines a process for information sharing, discussion of lessons learned, and identification of potential framework refinements. Insights derived from these reports should directly inform future DER orchestration applications.

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?

See PG&E's response to Question 2: "Priority Areas for Additional Development before IOUs file DER orchestration framework applications."

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

See PG&E's response to Question 2, "Priority Areas for Additional Development before IOUs file DER orchestration framework applications."

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

See PG&E's response to question 2 "Establish Process for the IOUs to Request Funding" for a summation of PG&E's recommendation on a regulatory pathway.

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?

Stakeholder working groups amongst utilities, DER providers, aggregators, technology vendors, and other stakeholders are most effective for addressing complex issues that will continue to evolve as demonstrations provide additional learnings. In particular, the topics around valuation and cost benefit approaches are well-suited for collaborative development because they will continue to evolve as utilities and third parties gain experience through demonstrations.

A common valuation and cost-benefit methodology should be established before IOUs seek large-scale deployment. This framework should consider:

- Comparison against traditional utility solutions
- Full accounting of orchestration costs
- Locational and temporal valuation
- Measurement of asset deferral
- Reliability and operational benefits
- Customer bill impacts
- Non-performance and remediation costs
- Early realization of revenue from speed to power applications
- Mechanisms that ensure distributed energy resources (DERs) and traditional utility investments are evaluated and incentivized on an equitable basis, consistent with the value they provide to customers and the electric system

Multiple parties emphasized that the central question for DER orchestration is whether it can deliver verifiable net ratepayer value at costs lower than traditional solutions. Some applications, like early customer energizations, also warrants study given this is a relatively new use case. Because valuation methodologies will likely evolve as additional data becomes available, continued stakeholder collaboration will help build consensus and improve consistency across utilities.

This approach allows California to continue advancing DER orchestration while ensuring that key implementation details are informed by practical experience and stakeholder expertise rather than theoretical assumptions alone.

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?

Meaningful engagement with California Tribal Nations, environmental and social justice (ESJ) communities, and other impacted communities should be an ongoing component of DER orchestration development. Consistent with discussions in High DER Track 3 regarding the value of continued stakeholder engagement and collaborative development processes, the Commission should consider periodic community-focused workshops and outreach sessions alongside the proposed DER orchestration working groups. Utilities should summarize stakeholder feedback and describe how it has been incorporated into demonstration activities and future applications. This approach will help ensure that DER orchestration implementation remains transparent, inclusive, and responsive to the needs of California's diverse communities.

In addition, the Commission and/or IOUs should establish mechanisms for fostering two-way communication that allow community perspectives to be incorporated throughout DER orchestration implementation. Leveraging established community engagement networks, including existing outreach efforts and partnerships with community-based organizations (CBOs), can help ensure customer feedback is gathered from communities that may face capacity, accessibility, or resource constraints. PG&E engages with a range of customer groups, including but not limited to, local government affairs, tribal entities, business energy solutions, historically underrepresented groups, through recurring workshops and events that provide opportunities to solicit community feedback and elevate community concerns. Feedback gathered from these engagement channels can be shared with appropriate utility teams, including distribution planning organization(s), to support consideration and incorporation of community

perspectives into distribution planning process. Community feedback, supplemented by High DER Proceeding's Equity Metrics, can support evaluation of accessibility and equitable outcomes to capacity resources, while informing continuous refinement of DER orchestration program design, customer engagement strategies, and implementation approaches.

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?

As discussed in PG&E's opening comments to the March 23, 2026 Assigned Commissioner's Ruling on Track 1 and Track 2 Distributed Energy Resources Orchestration (ACR), and during the May 21, 2026 workshop, PG&E has identified System Peak Reduction, Speed-to-Power, and Resource-Efficient Grid Investments as the primary use cases for DER orchestration. These use cases provide a framework for evaluating how DERs can be deployed to address emerging grid needs and deliver measurable ratepayer benefits. Within these broad categories, DER orchestration can support a range of grid services, including non-wires alternatives, bridge-to-wires solutions, reliability and contingency support, localized constraint management, peak load management, voltage support, flexible service arrangements, and managed electrification growth. However, these three categories should be understood as broad bucket starting points rather than an exhaustive list of all potential DER orchestration use cases. There are many additional and overlapping applications that may emerge depending on local grid conditions, customer needs, technology capabilities, and the availability of orchestrated resources.

The appropriate starting point should be driven by identified distribution grid needs and the ability of available DERs and orchestration technologies to provide measurable relief. Accordingly, PG&E recommends prioritizing use cases that address near-term, location-specific grid constraints where orchestration can provide the most immediate customer and ratepayer value. Localized overload mitigation and speed-to-power applications should generally be

implemented first where they can enable new business load to energize faster or manage potential overloads until a permanent grid solution is placed in service. Longer-term sequencing should be informed by operational experience, demonstrated DER performance, technology readiness, and the specific needs identified through distribution planning and operations. This flexible approach allows DER orchestration to provide short-term relief from overloads to the extent supported by available resources and technologies, while also building toward broader resource-efficient grid investment outcomes over time.

The specific emerging grid needs, operational priorities, and value of these services will vary across utility service territories based on differences in system conditions, load growth, electrification trends, DER adoption, and infrastructure requirements. Accordingly, the Commission should establish overarching principles and objectives for DER orchestration while allowing each IOU the flexibility to develop and prioritize a roadmap that reflects its unique grid needs and operational circumstances. This approach will enable utilities to target DER orchestration where it can provide the greatest value to customers and support the most cost-effective use of grid resources.

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?

The Commission should recognize that the IOUs are at different stages of technical maturity with respect to telemetry, communications infrastructure, DERMS, ADMS integration, and other DER orchestration capabilities. Rather than requiring all utilities to meet the same technical endpoint before implementation can proceed, the Commission should establish common objectives, guiding principles, reporting requirements, and performance metrics while allowing each IOU flexibility to pursue use cases and implementation activities aligned with its existing capabilities and emerging grid needs. A capability-based approach will enable utilities to advance DER orchestration at an appropriate pace while maintaining transparency and accountability through consistent evaluation criteria. Regular reporting and stakeholder

engagement will enable the Commission to use real-world implementation experience to refine future readiness criteria, application requirements, and deployment pathways, while allowing utilities with differing levels of readiness to continue making meaningful progress toward DER orchestration objectives.

11. How can current AMI 1.0 and Next-Generation AMI 2.0 Grid Edge DERMS capabilities support IOU-led DSO DER Orchestration programs?

AMI 1.0, AMI 2.0, and Grid Edge DERMS capabilities can provide important building blocks for IOU-led DER orchestration by improving visibility into customer load, DER performance, and distribution system conditions. These capabilities can support use cases such as system peak reduction, managed EV charging, load flexibility, constraint management, and infrastructure deferral by providing greater situational awareness, enhanced monitoring, and the ability to coordinate grid-edge resources. As advanced metering, communications, and grid-edge technologies evolve, utilities will have increased ability to identify localized emerging grid needs, evaluate DER performance, and verify delivery of grid services. AMI 2.0 and Grid Edge DERMS capabilities can also provide enhanced functionality to support more granular monitoring, improved data collection, and stronger integration between customer-facing DERs and utility operational systems.

a. What additional communications or technical capabilities are necessary to enable reliable dispatch and settlement of DERS via grid edge DERMS?

Reliable dispatch and settlement of DERs will require additional capabilities beyond metering and visibility. These include interoperable communications standards, timely telemetry, secure data exchange, measurement and verification capabilities, device registration and enrollment processes, forecasting tools, and the ability to communicate operational constraints and dispatch instructions. Depending on the use case, utilities may also require varying levels of latency, granularity, and performance verification to support operational decision-making. Open and interoperable communications architectures should be prioritized to enable participation

from a broad range of DER technologies, aggregators, and service providers while maintaining cybersecurity and customer privacy protections.

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?

Grid Edge DERMS and centralized Enterprise DERMS can play complementary roles within a DER orchestration framework, with each providing distinct capabilities that support different grid needs and operational objectives. Grid Edge DERMS solutions are generally designed to provide visibility and control closer to customer-sited resources and localized distribution constraints. These systems can support management of secondary distribution infrastructure, including service conductors, shared secondary networks, and service transformers, by monitoring near real-time conditions and coordinating customer resources to avoid overloads. As a result, Grid Edge DERMS may enable applications such as flexible interconnection, panel upgrade avoidance, secondary system upgrade deferrals, and accelerated residential customer energization. This capability can also enable distributed resources to be leveraged for other use cases beyond the secondary distribution grid when connected to the Enterprise DERMS. The Grid Edge DERMS also has the potential to mitigate risks to functionality and system stability due to loss of internet or disruptions to third party communications or cloud-based systems. The primary challenges to Grid Edge DERMS is the need for devices to remain connected with AMI 2.0 meters and the need for open standards in devices communicating within the home.

By comparison, Enterprise DERMS platforms are generally designed to provide a system-wide operational view and integrate DER orchestration with utility planning, forecasting, outage management, ADMS, and distribution operations. This centralized view enables utilities to evaluate and prioritize DER dispatch across multiple circuits and use cases, ensuring that local actions remain aligned with broader distribution system reliability, safety, and operational objectives. Enterprise DERMS can also aggregate visibility across large DER populations,

support portfolio-level forecasting and optimization, provide consistent performance measurement and verification, and facilitate coordination between distribution operations and wholesale market activities.

Rather than prescribing a specific architecture, the Commission should focus on the capabilities required to support specific grid services and use cases. Utilities should have flexibility to leverage Grid Edge DERMS, Enterprise DERMS, or a combination of both, provided they can demonstrate reliable performance, interoperability, cybersecurity, and measurable ratepayer benefits.

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 variety of customer-owned DER technologies can participate in IOU-led DER orchestration programs. This includes IOU direct orchestration of grid edge devices and a model with IOUs as the DSO, orchestrating DERs provided by different flexibility providers. The DER's suitability will depend on the specific grid service being procured, the level of performance required, and devices that are available in a specified area. For example, managed EV charging, smart thermostats, water heaters, and other flexible loads may be effective for peak management or load shaping, while customer-sited batteries may be better suited for reliability support, contingency response, localized constraint management, and infrastructure deferral applications. Customer-sited batteries, electric vehicles and managed EV charging systems, smart thermostats, smart water heaters, heat pump systems, smart panels, and other flexible loads are among the more mature technologies for providing grid services through coordinated orchestration. These technologies can support a range of use cases, including system peak reduction, distribution constraint management, speed-to-power solutions, managed electrification, reliability support, and infrastructure deferral. In many cases, these technologies are already commercially available, can receive control signals through aggregators or utility

programs, and have demonstrated the ability to modify load or inject energy in response to operational needs.

The Commission should avoid prescribing specific technologies and instead focus on the capabilities necessary to provide a given grid service, such as visibility, controllability, interoperability, measurement and verification, and dependable performance. A technology-neutral approach will enable utilities, customers, aggregators, and technology providers to deploy the resources that can most cost-effectively address identified grid needs and deliver maximum ratepayer value. Through demonstration activities and pilot deployments, PG&E will evaluate the performance of various DER technologies and develop a better understanding of which resources are best suited to address specific grid needs and provide particular grid services.

Additionally, as discussed in PG&E's May 21, 2026 workshop presentation, PG&E envisions multiple pathways for enabling and compensating DER participation. Depending on the use case, value may be exchanged through the provision of utility services that support customer objectives, such as accelerated interconnection, flexible service arrangements, managed charging programs, or avoided customer infrastructure upgrades. In other cases, PG&E may competitively procure DER flexibility to address identified grid needs. A flexible compensation framework will allow utilities to match the procurement approach to the specific grid service being sought and what's available, while promoting customer participation, innovation, and cost-effective outcomes for ratepayers.

a. What technical or operational barriers remain for broader participation?

Despite significant progress in DER adoption and grid modernization, several technical and operational barriers remain to broader DER participation. Key technical challenges include limited visibility into behind-the-meter DERs, inconsistent telemetry capabilities, lack of interoperability across devices and vendors, fragmented communications architectures, and varying levels of DER controllability. In addition, utilities, aggregators, and DER providers continue to face challenges integrating DER data and operational capabilities across multiple

platforms, including ADMS, DERMS, customer programs, and market systems. While individual DER technologies have historically participated in grid services on a standalone basis, as discussed above, the broader technology ecosystem remains fragmented and generally lacks a unified entity or control point capable of coordinating the full suite of behind-the-meter resources within a customer premise. To fully realize the potential of behind-the-meter DERs, continued evolution of the technology ecosystem will be necessary, including the development of interoperability standards, coordination mechanisms, and aggregation capabilities that enable multiple resource types to operate in concert and provide grid services in a reliable and scalable manner. Such advancements will enhance the ability of DER portfolios to deliver greater system value and support a broader range of distribution grid needs.

These challenges can make it difficult to reliably forecast, dispatch, verify, and measure DER performance at the scale necessary to support planning and operational decisions. Operational barriers also remain, including the need for standardized performance measurement and verification approaches, customer enrollment and retention challenges, scalable dispatch processes, and mechanisms to coordinate DER participation across multiple programs and market opportunities (including dual participation rules). As utilities gain experience through demonstration activities, many of these barriers can be addressed through an iterative, evidence-based implementation process.

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?

When determining the dependability of orchestrated DERs on the distribution grid, IOUs should account for customer behavior and resource availability using performance-based methodologies supported by empirical data. Customer-owned DERs should not be assumed to always provide their full nameplate capability. Instead, utilities should evaluate resource

dependability based on demonstrated performance, historical participation rates, dispatch response rates, seasonal operating characteristics, technology-specific limitations, customer enrollment and retention trends, and other factors that affect resource availability. Similar to existing demand-side management and demand response programs, utilities should apply appropriate diversity, availability, and performance factors when determining the amount of DER capacity that can be relied upon for planning and operational purposes. The Commission should allow utilities to develop and refine these methodologies through demonstration activities and operational experience. As additional performance data becomes available, utilities can improve forecasting approaches and establish increasingly accurate estimates of dependable DER capacity for specific technologies, customer segments, grid services, and operating conditions. This performance-based approach enables DERs to provide increasing value to grid planning and operations while ensuring that reliability is maintained through appropriate forecasting assumptions, measurement and verification requirements, operational safeguards, and contingency planning. Resources that demonstrate consistent and reliable performance over time should be afforded greater planning and operational value than resources with more limited or uncertain availability.

Furthermore, it will be important to determine and define what responsibilities will be required for participating DERs and what liability for failure to meet the needs of other customers or other impacts to the grid should be instituted. Therefore, it will be important to consider liability items (e.g., qualifying conditions, insurance provisions, remediation plans, etc.) to ensure reliable integration of customer-owned DERs into IOU DER orchestration programs.

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?

PG&E's EPIC 4.08 project is intended to develop the capability and framework for modeling, integrating, and validating load flexibility within the distribution planning and execution process (DPEP). Given the uncertainty associated with demand flexibility, it should be

incorporated into scenario planning to evaluate its impact on investment priorities. In the near term, this work can help IOU DSOs compare scenarios with and without reliable demand flexibility and translate those findings into one investment plan that balances reliability and affordability. This work also lays the foundation for incorporating demand flexibility into the IEPR-based planning forecast as such assumptions become available and sufficiently validated, so that future planning cycles can reflect demand flexibility in a consistent, transparent, and planning-relevant manner.

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.1 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 Process (DPEP) and how would that be accomplished?

The demand flexibility sensitivity scenario identified in EIS 2 demonstrates the need to carefully define planning-grade flexibility before it can be relied upon in distribution planning. Demand flexibility remains an evolving capability that depends on available technologies, customer adoption of behind-the-meter assets, and the variability of customer responses to triggering signals. These factors influence the ability to develop planning-grade forecasts that estimate existing and future flexible load at different grid levels and assess how flexibility may change hourly load shapes across programs, rates, technologies, and levels of controllability. Integrating demand flexibility into DPEP will require confidence that orchestrated resources can perform as expected, supported by sufficient visibility, validation, and trust. Achieving that confidence will require enabling technologies and clear operational processes.

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?

A successful DER orchestration framework should be built around the principle that DERs complement, rather than compromise, safe and reliable grid operations. To support this objective, the framework should include several foundational components: (1) visibility into DER location, status, characteristics and performance; (2) interoperable communications and data exchange capabilities; (3) integration of DERs into utility planning and operational processes through systems such as ADMS and DERMS; (4) clear operational roles and responsibilities among utilities, customers, aggregators, and other market participants; (5) measurement and verification processes to confirm performance; and (6) cybersecurity and customer data protection requirements. The framework should also enable the DSO to identify emerging grid needs, communicate operational constraints, monitor system conditions, and verify that orchestrated resources are delivering the services required to maintain reliability and system performance. At the same time, the framework should support flexibility by adopting a capability-based and technology-neutral approach. Rather than prescribing specific technologies or operational models, the Commission should focus on the capabilities necessary to provide grid services, including visibility, controllability, interoperability, and dependable performance. The framework should support a range of participation models, including utility-managed programs, aggregator-managed resources, market-based approaches, and customer-responsive technologies. As DER penetration grows, the framework should leverage open communications standards, scalable dispatch mechanisms, and data-sharing processes that allow DERs to respond dynamically to changing grid conditions while preserving customer choice and enabling innovation. Demonstration activities and pilot programs should continue to play a key role in validating operational requirements, refining performance expectations, and informing the evolution of the framework as utilities gain experience integrating increasing levels of DERs into grid planning and operations.

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.

The primary opportunities for lowering costs through DER orchestration are the ability to enable and accelerate customer energizations and the ability to improve distribution planning so that it can reduce or defer investments that would otherwise be required to serve growing demand. PG&E's EIS 2 found that "electrification growth may provide downward pressure on distribution rates by as much as 25% by 2040," [1] indicating that long-term affordability may be driven by enabling electrification growth and efficiently serving new customer loads. As discussed in PG&E's workshop materials, DER orchestration can help address grid needs through use cases such as System Peak Reduction, Speed-to-Power, and Resource-Efficient Grid Investments.

In the near term, cost savings are likely to be achieved through targeted applications that address specific distribution system needs, including managed EV charging to defer secondary service transformer replacements, flexible load management to mitigate overload conditions, customer-sited batteries that support reliability and contingency events, and temporary "bridge-to-wires" solutions (e.g. Flex Connect) that enable customers to receive service while longer-term infrastructure upgrades are developed. The Flex Connect use case also enables loads to come online faster, thus creating additional revenues that can help offset system costs. These initial implementations can reduce near-term capital expenditures, improve asset utilization, accelerate customer electrification, and provide greater flexibility in managing localized grid constraints. As DER orchestration capabilities mature and deployment scales, the opportunity shifts from addressing individual grid needs to enabling broader system-wide optimization. Increased DER visibility, improved forecasting, enhanced interoperability, and greater operational experience can allow orchestrated DERs to be incorporated into planning, operations,

[1] PG&E, Electrification Impacts Study (EIS) Part 2 Final Report, p. 14

and investment decision-making processes. Over time, this may enable more efficient sizing and timing of distribution system upgrades, improved management of electrification-driven load growth, expanded use of non-wires and bridge-to-wires solutions, and more effective coordination between customer-sited resources and utility operations. As participation increases and operational capabilities mature (including, but not limited to, that ability to value stack resources to serve multiple grid needs), economies of scale may reduce program administration and technology integration costs while increasing the value that DERs can provide to ratepayers. The magnitude of these opportunities will vary by utility and location and should be evaluated based on the specific grid needs being addressed and demonstrated performance of orchestrated DERs.

In addition, PG&E supports the CPUC finalizing a common set of affordability metrics to apply consistently across programs to prevent increasing costs for non-participating customers or transferring participant-specific costs to the broader rate base. PG&E is proposing multiple affordability outcomes as a starting point for developing these metrics as part of its Opening Comments on the Assigned Commissioner's Proposal on Flexible Connections in the High-DER Track 3 proceeding. These outcomes include: net ratepayer benefits; preventing new or additional cost shifts; only including avoided costs that are verifiable, measurable, and realized; and no double compensation. PG&E believes this discussion should be coordinated between Track 2 and Track 3.

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?

PG&E has no recommendations at this time for other relevant issues that the Commission should consider.

III. CONCLUSION

PG&E appreciates the opportunity to provide these responses to the questions posed in the Ruling.

Respectfully Submitted,

BENJAMIN C. ELLIS

By: */s/ Benjamin C. Ellis*
BENJAMIN C. ELLIS

Pacific Gas and Electric Company
300 Lakeside Drive, Suite 210
Oakland, CA 94612
Telephone: (415) 265-2678
E-Mail: ben.ellis@pge.com

Attorney for

Dated: July 27, 2026

PACIFIC GAS AND ELECTRIC COMPANY