BEFORE THE PUBLIC UTILITIES COMMISSION
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Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	Rulemaking 21-06-017 (Filed June 24, 2021)

SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902 E) OPENING COMMENTS ON THE ASSIGNED COMMISSIONER'S AND ADMINISTRATIVE LAW JUDGE'S RULING ISSUING QUESTIONS ON THE DISTRIBUTED ENERGY RESOURCES ORCHESTRATION WORKSHOP REPORTS

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I. INTRODUCTION

Pursuant to the California Public Utilities Commission's ("CPUC" or "Commission") July 9, 2026 *Assigned Commissioner's and Administrative Law Judge's Ruling Issuing Questions on the Distributed Energy Resources Orchestration Workshop Reports* ("Ruling"), San Diego Gas & Electric Company ("SDG&E") hereby submits these opening comments responding to the eighteen questions set forth in the Ruling.[1]

The Ruling enters into the record two Track 2 Distributed Energy Resources ("DER") Orchestration workshop reports: the Energy Division's report summarizing the May 21, 2026 workshop on Distribution System Operator ("DSO")-led DER Orchestration ("Workshop 1 Report"), and the report summarizing the June 5, 2026 workshop on Transmission System Operator ("TSO")-DSO Coordination ("Workshop 2 Report"), which SDG&E co-authored with staff of the California Independent System Operator ("CAISO"), Pacific Gas and Electric Company ("PG&E"), and Southern California Edison Company ("SCE"). SDG&E presented at both workshops. These workshops provided for early, substantive engagement among the Commission, the CAISO, the investor-owned utilities ("IOUs"), and stakeholders.

The positions expressed in these comments are consistent with SDG&E's April 20, 2026 response to the March 23, 2026 Assigned Commissioner's Ruling on Track 1 and Track 2 DER Orchestration ("SDG&E Opening Comments") and SDG&E's April 30, 2026 reply comments ("SDG&E Reply Comments"), as well as SDG&E's presentations at the May 21 and June 5 workshops. For the Commission's convenience, Section II.A below summarizes the core

[1] Ruling at 1 (opening comments due no later than July 27, 2026).

positions that inform SDG&E's responses, and Section II.B responds to each of the Ruling's questions in turn.

II. DISCUSSION

A. Overview of SDG&E's Position

SDG&E's responses to the Ruling's *questions* proceed from a small number of core positions, each developed in SDG&E's prior comments and workshop presentations:

> **Framework first.** The Commission should first develop and adopt a durable DER Orchestration Framework in Track 2 through structured workshops and/or a Commission-led working group supported by written party comments. A Commission decision would then be issued – before utility applications to implement orchestration programs are filed. The Framework is a prerequisite to any application, not a byproduct of one, because applications will be evaluated against the standards the Framework establishes.[2]
>
> **Applications should be optional and readiness-driven.** A utility should file an application to implement an orchestration program only when it determines it can begin implementation in a measured, cost-effective, and reliable manner. Applications would follow pilots that demonstrate that particular programs are likely to provide positive benefits at scale. The Commission should not mandate applications or impose uniform filing timelines.[3]
>
> **Pilots are prerequisites to implementation at scale.** Pilots demonstrate technical feasibility, commercial viability, operational integration, and participation pathways in ways that framework-level policy and modeling alone cannot.[4]
>
> **Technology and architecture are implementation details, not Framework mandates.** Choices among communications protocols, DER management system ("DERMS") architectures, and dispatch mechanisms should be made by each utility

[2] SDG&E Reply Comments at 1-7; SDG&E Opening Comments at 1-4.

[3] SDG&E Opening Comments at 15; SDG&E Reply Comments at 2.

[4] SDG&E Reply Comments at 7-8.

in its application, based on the specific grid need and the utility's operational maturity.[5]

Compensation discipline and cost-effectiveness are essential. DERs should be compensated for providing services that address identified distribution needs. DERs should not be compensated broadly for unidentified, speculative or conceptual future needs. Programs should be scaled only after cost-effectiveness has been demonstrated.[6]

Adequate cost recovery must accompany any Commission direction. Any Commission direction or requirement that a utility implement or begin DER orchestration should recognize whether existing funding is adequate and, if not, provide a dedicated cost recovery mechanism.[7]

B. Responses to the Ruling's 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?

SDG&E has reviewed both workshop reports and finds that they fairly and accurately summarize the workshop discussions, including the perspectives SDG&E presented. SDG&E co-authored the Workshop 2 Report with CAISO, PG&E, and SCE staff and confirms that it accurately reflects the June 5, 2026 workshop presentations and discussion.

SDG&E offers one clarification to the Workshop 1 Report. In summarizing SDG&E's remarks on cost-benefit and incentive topics, the report states that SDG&E "did not endorse shared savings mechanisms at this stage."[8] To be precise, SDG&E's position is that the utilities should have the opportunity, but not an obligation, to propose a shared savings mechanism ("SSM"), and that SDG&E remains neutral on SSM design pending further investigation.[9] SDG&E also noted that SSM design raises broader ratemaking questions that may be better

[5] SDG&E Reply Comments at 8-9.

[6] SDG&E Reply Comments at 11-12; SDG&E Opening Comments at 7-8.

[7] SDG&E Reply Comments at 9.

[8] Workshop 1 Report at 12.

[9] SDG&E Opening Comments at 10; SDG&E Workshop 1 Presentation, Slide 18.

addressed in a dedicated venue. SDG&E does not oppose SSMs; it simply believes their design and adoption should remain optional and be supported by an adequate record.

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?

The single most important additional step is for the Commission to complete and adopt the DER Orchestration Framework itself, in Track 2, before any applications are directed or filed. As SDG&E explained in its reply comments, the Framework is a prerequisite to any application that seeks authority to implement an orchestration program at scale, because applications will be evaluated against the standards the Framework establishes.[10] The Framework should be adopted on its own record. The framework would be informed by party comments, the workshops already held, and the additional working group or workshop processes discussed in response to Questions 4, 5, and 7 below. The framework should establish the procedural pathway, guiding principles, readiness thresholds, application content standards, and cost recovery architecture.

Before the Framework can meaningfully govern applications, the following substantive elements require development through a working group or structured workshop series, with the resulting work product subject to written party comment on the record:

1. a cost-benefit methodology, using the California Standard Practice Manual as a foundation. The cost-benefit methodology would incorporate distribution-specific values, including locational and temporal avoided-cost recognition, comparison against the traditional utility solution, full incremental cost accounting, and bill-impact analysis;[11]
2. performance metrics and measurement-and-verification ("M&V") standards;
3. pilot evaluation standards and the progression criteria that determine when pilot results are sufficient to support scaled programs;
4. the basis for verifying avoidance of conventional utility solutions;[12]

[10] SDG&E Reply Comments at 1-2.

[11] SDG&E Opening Comments at 7-8; SDG&E Workshop 1 Presentation, Slide 15.

[12] SDG&E Reply Comments at 11-12.

5. standard participation-model elements for tariffs and contracts, including roles, performance obligations, remedies, and data-exchange, privacy, and cybersecurity requirements;
6. the cost recovery architecture and the relationship between Track 2 framework issues and General Rate Case ("GRC") cost-recovery issues; and
7. the interface between DER orchestration and the Commission's demand response ("DR") policies and proceedings, discussed further in response to Question 18.[13]

With respect to timing, SDG&E recommends that the Commission convene the working group and/or workshop series following reply comments on this Ruling. After completion of the related work products, the Commission should provide an on-the-record opportunity for written party comment. A decision adopting the Framework would follow.

The Commission should not direct the IOUs to file applications on a fixed schedule. Applications should follow adoption of the Framework and should be filed when – and only when – a utility has identified cost-effective opportunities and developed the readiness to deliver. After the Framework is adopted, any utility that has completed the necessary pilot work and developed readiness retains a viable path to file promptly after the Framework is adopted.[14]

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 Framework itself is the appropriate vehicle for ensuring that pilot learnings and the record of this proceeding are incorporated into future applications. Specifically, the Framework should establish application content standards requiring each application to identify, for each proposed program: (a) the grid need the DER solution will mitigate; (b) the conventional utility solution that establishes the cost-effectiveness baseline; (c) DER compensation, where applicable; (d) estimated costs and benefits; (e) the DER performance attributes required to

[13] SDG&E Opening Comments at 13-14.

[14] SDG&E Reply Comments at 2-3.

address the grid need; (f) how DER performance will be measured; and (g) the remedial solution in the event of DER non-performance.[15] The Framework should further require applications to document the pilot results – the utility's own and, where relevant, other utilities' publicly available results – that support each of those showings, along with lessons learned and how they informed program design.

SDG&E's Enterprise DERMS procurement is targeted for 2027, and pilot-capable environments are anticipated post-2027; some pilots may depend on DERMS infrastructure where the program relies on location- and time-specific grid conditions, while others may be possible with the operational infrastructure currently in place.[16]

b. Coordinate the pilots with the formal DER orchestration application proceeding?

SDG&E recommends three coordination mechanisms. First, the Framework should define a standardized pilot-reporting template so that pilot designs, results, and lessons learned are documented consistently across the IOUs and are usable in subsequent application proceedings. Second, the IOUs could serve periodic pilot status reports in Track 2 (or to the working group, if convened), ensuring that pilot learnings enter the record on an ongoing basis rather than only at the time of an application. Third, pilots conducted under existing authority – for example, GRC-funded, Electric Program Investment Charge ("EPIC"), or DR program activities – a should be creditable toward the Framework's readiness and progression showings, so that applications are not required to duplicate demonstrations already completed in other venues.

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?

The Commission should convene a Commission-led working group, a structured workshop series, or a combination of both, culminating in a Commission decision adopting the Framework, before applications are filed. SDG&E made this recommendation in its reply comments, agreeing with the Public Advocates Office ("Cal Advocates") that a Track 2 working group should develop the necessary cost-benefit methodology, performance metrics, pilot

[15] SDG&E Workshop 1 Presentation, Slide 8.

[16] SDG&E Workshop 1 Presentation, Slides 20-21.

evaluation standards, and oversight framework, and with the California Efficiency + Demand Management Council that a structured workshop series would allow stakeholders and the IOUs to collaborate on orchestration solutions. The content that must be resolved before any application can be meaningfully evaluated is substantial, and a single workshop is an exceedingly broad mandate for that task.[17]

In addition to the working group/workshop process, two coordination steps should be completed pre-application: (1) clarification of the relationship between DER orchestration and the Commission's DR policies and proceedings (see response to Question 18); and (2) alignment with the CAISO's Operational Coordination Framework process on TSO-DSO topics. Alignment with the CAISO process will help ensure that Commission processes complement – rather than duplicate – the detailed use-case and data-exchange work occurring in the CAISO's Industry Expert Working Group.[18]

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

The record in this proceeding indicates convening a working group or workshops is indeed warranted. The explicit objective of the working group or workshop series should be to produce the analytical and policy building blocks the Commission needs to adopt the DER Orchestration Framework. The Framework establishes how the subsequent program-specific applications will be evaluated. The work products from the DER Orchestration Framework working group or workshop series should be subject to written party comment, on the record, before adoption.

The key topics should include:

1. Cost-benefit methodology: locational and temporal avoided-cost recognition; comparison against the traditional utility solution as the baseline; full incremental cost accounting (platform, telemetry, settlement, M&V, administration, customer or third-party compensation, and any device-signaling licensing costs); and bill-impact analysis conducted separately from net-benefit analysis;

[17] SDG&E Reply Comments at 6-7.

[18] Workshop 2 Report at 5-6; see also SCE's discussion of the CAISO working group as the appropriate forum for detailed use-case development, Workshop 2 Report at 8.

2. Performance metrics and M&V protocols, including how DER performance in providing distribution services is quantified for purposes of planning and operations;
3. Pilot evaluation standards and progression criteria — what pilot results or field demonstrations are sufficient to authorize ratepayer funding for broader implementation;
4. The verification basis for avoidance of conventional utility solutions;
5. Participation models and standard tariff/contract elements: roles and responsibilities of the DSO, aggregators, community choice aggregators ("CCAs"), and customers; minimum performance requirements; testing requirements; remedies for non-performance; and data-exchange procedures;
6. Privacy and cybersecurity requirements for DER data exchange;
7. Cost recovery architecture, including the relationship between Track 2 framework issues and GRC cost-recovery issues; and
8. The interface between DER orchestration and DR programs, protocols, and proceedings.

The working group should not attempt to prescribe technologies, communications protocols, or system architectures. Those are implementation choices appropriately made by each utility in any future pilot or application, based on its operational maturity and the specific grid need. Prescribing them at the Framework level would risk stranding investments and foreclosing innovation.[19]

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

SDG&E continues to recommend the two-step regulatory pathway described in its opening and reply comments. First, the Commission adopts a durable, Commission-approved DER Orchestration Framework in Track 2, on a standalone record supported by the working group/workshop process described above. The Framework establishes principles, criteria, application content standards, readiness thresholds, governance processes, and the cost recovery architecture. Second, utilities file optional, readiness-driven applications proposing specific

[19] SDG&E Reply Comments at 8-9.

programs under which DERs would provide identified distribution services, with each application evaluated for consistency with the Framework and supported by a cost-effectiveness showing.[20]

On cost recovery, SDG&E recommends the Framework recognize three distinct cost categories with corresponding recovery vehicles: (1) foundational capital – ADMS, DERMS, and communications infrastructure – recovered through GRCs and Grid Modernization Plans; (2) framework-establishment costs, if applicable, recorded to a memorandum account subject to subsequent reasonableness review; and (3) program-specific costs including incentives, recovered through a program-level mechanism approved with the program. Any Commission direction or requirement that a utility implement or begin DER orchestration should recognize whether existing funding is adequate and, if not, provide a dedicated cost recovery mechanism.[21]

SDG&E respectfully disagrees with two categories of alternative pathways offered in the record. First, the Commission should not mandate application filings on a fixed, uniform timeline. A utility should file only when it can begin implementation in a measured, cost-effective, and reliable manner. Second, the Commission should not direct the development of statewide market platforms – such as the accelerated 12-to-18-month platform deployment proposed by the Utility Consumers' Action Network ("UCAN") at Workshop 1 – before the Framework's cost-benefit methodology, performance standards, and verification requirements are in place. Developing market platforms in advance of demonstrated, cost-effective, need inverts the proper sequence and creates a high probability of ratepayers paying for systems that are not needed or deliver services at a higher cost than other alternatives.

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?

The topics best suited for development through a working group or future workshops are those that define the common standards against which all applications will be evaluated; i.e., the DER Orchestration Framework.

Topic 4 (Cost-Benefit Methodologies and Valuation Frameworks) is the highest priority. A common methodology – perhaps, grounded on the California Standard

[20] SDG&E Opening Comments at 1-4; SDG&E Reply Comments at 1-3.

[21] SDG&E Workshop 1 Presentation, Slide 23; SDG&E Reply Comments at 9.

Practice Manual – must exist before any application's cost-effectiveness showing can be evaluated.[22]

Topic 3 (Dispatch Mechanisms and Aggregator Roles), as to the standard elements of tariffs and contracts: role definitions, minimum performance requirements, testing, M&V, remedies, and accountability mechanisms. The specific dispatch architecture (e.g., dynamic operating envelopes versus scheduled dispatch) should remain an implementation choice.

Topic 2 (Open, Interoperable Communications), as to data-sharing frameworks, privacy protections, and cybersecurity requirements. The working group should establish interoperability and open-access principles, but should not mandate specific communications protocols; protocol selection (IEEE 2030.5, OpenADR, or others) is an implementation choice.[23]

Topic 5 (Incentive Structures and Mechanisms), to the extent pursued – with the caveat that SSM design raises significant ratemaking questions that may be better addressed in a dedicated venue, and that any review of foreign regulatory structures (e.g., Ofgem, the Australian Energy Regulator) would benefit from participation by experts with direct experience in those jurisdictions.[24]

By contrast, Topics 1 and 6 are inherently utility-specific and are best developed in specific program applications rather than working groups. DER-provided grid services (Topic 1) must be anchored to specific, identified grid needs. Program readiness (Topic 6) turns on each utility's system conditions, platforms, and operational maturity. The working group can usefully standardize the categories of readiness criteria and the template for grid need showings, but the substantive demonstrations belong in each utility's program-specific applications.[25]

[22] SDG&E Opening Comments at 7-8.

[23] SDG&E Workshop 1 Presentation, Slide 11; SDG&E Reply Comments at 8-9.

[24] SDG&E Opening Comments at 11-12.

[25] SDG&E Opening Comments at 15; SDG&E Workshop 1 Presentation, Slide 19.

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?

SDG&E supports early, accessible, and proportionate engagement, and notes that "Equity and Customer Protection" is already among the draft guiding principles SDG&E supports.[26] As required by the Commission, SDG&E has published a Community Engagement Plan ("CEP") which describes the numerous processes by which SDG&E obtains and responds to the needs of disadvantaged communities.[27] In general, SDG&E recommends the following approaches:

1. Plain-language materials. The Commission should develop plain-language summaries of framework documents, workshop notices, and comment opportunities that explain what DER orchestration is, what decisions are being made, and how communities may be affected, without requiring familiarity with the proceeding's technical record.
2. Use of established engagement structures. Engagement should proceed through the Commission's Tribal Consultation Policy and Environmental and Social Justice ("ESJ") Action Plan processes, and through the IOUs' existing community engagement channels – tribal liaisons, community-based organizations, and regional engagement forums – rather than creating parallel structures that communities must separately discover and track.
3. Accessible participation formats. Workshops and working group sessions addressing topics with community impacts should offer hybrid and remote participation, and where feasible be scheduled to accommodate participants who cannot attend during standard business hours.
4. Awareness of intervenor compensation. The Commission should ensure that materials directed to communities include information about the intervenor

[26] SDG&E Opening Comments at 8-9.

[27] SDG&E Revised Annual Service Territory Community Engagement Plan to Address Equity in the Distribution Planning Process, filed May 1, 2026. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M606/K600/606600369.PDF.

compensation program, which can help address financial constraints on participation in the formal proceeding.

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?

PG&E's three use cases are reasonable candidates, assuming the need for those three actions actually exist within the SDG&E service area. SDG&E notes that these actions overlap substantially with the candidate distribution services SDG&E identified in its opening comments and Workshop 1 presentation – including real-time thermal overload mitigation, distribution upgrade deferral, speed-to-power applications, and vehicle-to-grid ("V2G") services.[28] SDG&E defers to PG&E regarding the appropriate sequencing for PG&E's system. However, SDG&E offers three observations for the Commission's consideration.

First, the Commission should not adopt a universal, prescriptive use-case sequence applicable to all IOUs. Whether a use case is "correct" – and when it should be implemented – depends on each utility's identified grid needs, system conditions, and readiness. For example, SDG&E has to date not had a need to employ bridging/speed-to-power solutions on its system, and the DIDF experience suggests that commercially viable distribution-deferral opportunities at ratepayer-beneficial compensation levels have been limited, although growing V2G-capable electric vehicle adoption and battery density may change that calculus over time.[29]

Second, system peak reduction is largely a system-level service that overlaps significantly with existing DR programs and wholesale market participation pathways. Before it is implemented as a DSO-led "orchestration" use case, the interface with the Commission's DR policies, cost-effectiveness protocols, and the new DR rulemaking (R.25-09-004) should be clarified to avoid duplicative programs and double compensation.[30] SDG&E notes that "system peak reduction" is only a benefit to the extent that the lower peak results in ratepayer savings that

[28] SDG&E Opening Comments at 5-7; SDG&E Workshop 1 Presentation, Slide 7; Workshop 1 Report at 3-4.

[29] SDG&E Opening Comments at 5-6, 12-13.

[30] SDG&E Opening Comments at 13-14; see also response to Question 18.

offset the costs of obtaining that reduction. By itself, a lower system peak will reduce electric revenues and therefore require higher rates in order to recover the fixed costs of the electric grid.

Third, sequencing should be resolved the same way every other implementation question should be resolved: each use case should proceed when a specific identified need, a cost-effectiveness showing consistent with the Framework, and demonstrated readiness support the use case. Those are showings appropriately made – and evaluated – in utility applications under the adopted Framework, not determined generically in advance.

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 adopt a common Framework and permit utility-specific implementation pathways within it. Specifically, the Commission should: (1) establish consistent guiding principles, cost-benefit methodology, performance-metric categories, and readiness criteria through the Framework, so that all utilities are held to a common standard; (2) allow each utility to propose its own implementation pathway, sequence, and timing based on its system conditions, existing platforms, and operational maturity; and (3) decline to mandate uniform filing timelines or scope requirements. Meaningful progress does not require identical starting points; utilities that have completed pilot work and developed readiness can file promptly after Framework adoption, while others build the necessary capabilities.[31]

Regarding SDG&E's own readiness: SDG&E's foundational Advanced Distribution Management System ("ADMS") and day-ahead feeder forecasting capabilities are operational and being refined. SDG&E does not have a DERMS today. Enterprise DERMS procurement is targeted for 2027; and pilot-capable environments are anticipated post-2027. The Commission should recognize that some pilots may depend on DERMS availability – particularly programs that rely on location- and time-specific grid conditions – while others may be feasible with the operational infrastructure currently in place.[32]

[31] SDG&E Opening Comments at 15; SDG&E Workshop 1 Presentation, Slide 19; SDG&E Reply Comments at 2-3.

[32] SDG&E Workshop 1 Presentation, Slides 19-20; Workshop 2 Report at 9-10.

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 2.0 is expected to provide higher-resolution data that enhances DER visibility, system modeling, forecasting accuracy, and data validation. SDG&E anticipates that AMI 2.0 deployment will materially strengthen the customer/AMI visibility layer.

SDG&E has previously advised the Commission that its existing AMI 1.0 "is experiencing increasing failures, technological obsolescence, and limited vendor support," and that SDG&E has filed an application seeking approval of a modernized Smart Meter ("SM") 2.0 metering infrastructure program to address that risk and to build the foundation for future capabilities.[33] SDG&E's testimony, submitted with its Smart Meter 2.0 application,[34] states that the SM 2.0 transition "lays the groundwork for advanced technologies such as meter-level visibility and compute intelligence (also known as edge computing or grid-edge computing)," and describes the integration of compute intelligence "directly into the meter hardware," with local processing at the meter.[35]

However, in its Smart Meter 2.0 application, SDG&E requests approval to implement only a limited set of enhanced ("NextGen") capabilities on top of the base metering solution: (i) Customer Insights: Real-Time Energy Monitoring, an opt-in residential capability that provides data to the customer (not to the utility); and (ii) a Transformer Health & Load Management bundle, which includes Transformer Health & Load Management, Meter-Transformer Mapping, and Phase Identification.[36] These capabilities are enabled by Grid Edge Applications – software embedded in the meter that processes data locally – together with a vendor-hosted analytics platform.[37]

The NextGen capabilities SDG&E has requested are *visibility and analytics* capabilities. Transformer Health & Load Management delivers higher-resolution interval data, improved grid

[33] *Reply Comments of San Diego Gas & Electric Company in Response to Assigned Commissioner's Ruling Seeking Additional Information on DER Enabled Near Term Flexible Connections* at 13.

[34] Application of San Diego Gas & Electric Company (U 902 M) for Approval of Smart Meter 2.0 Proposal, A.25-12-012. See SDG&E January 2, 2026 Reply Comments at 13-14 & n.24.

[35] Ex. SDG&E-03 (Thai/Baugh), Chapter 3 (Smart Meter 2.0 Proposal and Options Evaluated), A.25-12-012 (Dec. 18, 2025) (Redacted Public Version) ("SM 2.0 Ch. 3") at DT/BB-3, DT/BB-5.

[36] SM 2.0 Ch. 3 at DT/BB-8 to DT/BB-9.

[37] SM 2.0 Ch. 3 at DT/BB-9 to DT/BB-10.

visibility, earlier detection of emerging issues, and automated notification for operations. Meter-Transformer Mapping and Phase Identification improve the accuracy of SDG&E's connectivity model.[38] The capabilities will identify overload risk and inform operators, who then respond through conventional means.

In SDG&E's view, AMI capabilities – including grid-edge analytics that next-generation metering may enable – are a complement to, not a substitute for, the operational systems (ADMS/DERMS) that perform dispatch coordination for location- and time-specific grid services.

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 – whether executed through grid-edge platforms or centralized systems – would require:

1. a secure, low-latency communications path to the device or its aggregator, with confirmation that dispatch signals were received and acted upon;
2. settlement-grade measurement and verification;
3. integration with SDG&E's Distributed Interconnection Information System ("DIIS"), the utility's DER registry, as well as DERMS and ADMS platforms, to ensure dispatch decisions account for real-time feeder conditions, network topology, and switching states;
4. cybersecurity conformance and privacy safeguards governing the data exchanged; and
5. performance requirements, testing protocols, baseline methodology, and remedies established via tariff or contract.

SDG&E also reiterates a structural barrier that no metering or DERMS platform resolves: many DER devices cannot be signaled directly without contracting with a separate company, agreeing to certain services, and the payment of licensing fees to the device manufacturer, whose proprietary cloud is often the only communications pathway to the device. These licensing costs, and the restrictive business model they stem from, must be counted in any cost-effectiveness

[38] SM 2.0 Ch. 3 at DT/BB-30 to DT/BB-31.

assessment, and overcoming the barrier itself likely requires legislative action and/or codes-and-standards changes.[39]

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 concepts locate intelligence at or near the meter. Their potential advantages include localized sensing (including visibility into secondary-system conditions that centralized systems do not directly observe), reduced latency for local control actions, and distributed scalability of localized functions. Their disadvantages are that they remain emerging and largely unproven at scale for orchestration purposes, and that localized decisions must in any event remain coordinated with feeder-level and system-level operations – an orchestrated dispatch that is locally optimal but inconsistent with feeder conditions or CAISO market outcomes does not serve reliability.

Centralized Enterprise DERMS provides the operational coordination layer – telemetry ingestion, DER registry integration, and dispatch coordination – integrated with ADMS feeder operations and state estimation, geographic information systems, and enterprise forecasting platforms. That integration is what enables location- and time-specific orchestration, distribution-level constraint management, and the aggregated visibility and scheduling coordination needed at the CAISO interface. SDG&E's planned path is Enterprise DERMS procurement in 2027, integrated with its Distribution Interconnection Information System ("DIIS") DER registry and ADMS, with AMI 2.0 enhancing the customer/AMI visibility layer over time. SDG&E views enterprise and grid-edge capabilities as potentially complementary rather than competing.[40]

Consistent with SDG&E's broader position, the choice among DERMS architectures is an implementation decision that should be made by each utility based on the specific services proposed and the utility's operational maturity; the Framework should remain technology-neutral and should not mandate a particular architecture.[41]

[39] SDG&E Opening Comments at 13, 16.

[40] SDG&E Workshop 2 Presentation, Slides 10-12; Workshop 2 Report at 9-10.

[41] SDG&E Reply Comments at 8-9.

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?

Capability should be assessed against the service to be provided – the same "fit-for-purpose" discipline SDG&E advocates for visibility requirements.[42] With that caveat, SDG&E offers the following assessment:

> **Behind-the-meter battery storage** is the nearest-term fit for location- and time-specific distribution services. Batteries are dispatchable, provide fast and precise response, can absorb as well as inject power (including reactive power support from inverter-based systems), and are frequently capable of telemetry through their management platforms.[43]
>
> **Managed EV charging** represents a large and rapidly growing flexible load that can be scheduled or curtailed to reduce loading on at-risk equipment. V2G capability is emerging and may, over time, create circuit-level deferral opportunities not previously available; V2G remains at the pilot-scale investigation stage.[44]
>
> **Smart thermostats, electric water heaters, and similar flexible loads** have established value in demand-response-type applications. However, compared to battery storage, their response may be less firm, less precise, and more dependent on customer behavior (including customer override actions), which makes them better suited to portfolio-level, system-peak applications than to circuit-specific services requiring high dependability.

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

The principal barriers include:

1. Device signaling limitations and manufacturer licensing fees. Many devices can only be signaled through the manufacturer's proprietary cloud, for a fee that continues to rise; manufacturers often do not permit open communication with

[42] SDG&E Workshop 1 Presentation, Slide 11; Workshop 1 Report at 7-8.

[43] SDG&E Opening Comments at 5.

[44] SDG&E Opening Comments at 5, 13; SDG&E Workshop 1 Presentation, Slide 7.

their devices. This business-model constraint appears to be outside the control of the IOUs or the Commission, and likely requires legislative and/or codes-and-standards action to resolve.[45]

2. Standards immaturity and legacy devices. As discussed at Workshop 1, key standards referenced in this proceeding lack the implementation specificity needed to build systems, certified products for some device categories remain scarce, and millions of installed legacy devices (Z-Wave, ZigBee, Modbus, and similar protocols) currently have no pathway to participate.[46]
3. Aggregator readiness and operational complexity, particularly the complexity of coordinating and dispatching specific subsets of DERs when resources are aggregated.
4. Telemetry, settlement, and M&V costs relative to the value of the service provided.
5. Customer acquisition costs, customer interest, and compensation expectations – DER owners will require compensation sufficient to permit utility dispatch, and at compensation levels that provide overall ratepayer benefit. Opportunities have to date been limited.
6. Dependability for planning-grade commitments, discussed in response to Question 13.[47]
7. Unresolved overlap with DR programs, protocols, and cost-effectiveness frameworks (see response to Question 18).

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

Reliable integration should be established through the tariffs and/or contracts under which DERs provide each specific service. Those instruments should set forth: (1) minimum performance requirements, including magnitude, duration, response time, and availability windows; (2) testing and commissioning requirements demonstrating capability and readiness before enrollment; (3) M&V protocols appropriate to the service; (4) telemetry or data-reporting

[45] SDG&E Opening Comments at 13, 16.

[46] Workshop 1 Report at 9 (summarizing Universal Devices).

[47] SDG&E Opening Comments at 4-6.

requirements matched – on a fit-for-purpose basis – to the service provided; (5) remedies and penalties for substandard performance; (6) data-exchange procedures with privacy safeguards and cybersecurity requirements; and (7) compliance with applicable interconnection requirements. Where aggregators participate, the aggregator should commit resources, manage customers and devices, and bear the performance obligation.[48]

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

Dependability of DERs in delivering services should be quantified conservatively and empirically. SDG&E recommends that the Framework's performance-metric and M&V standards address:

1. Derating of expected contributions based on demonstrated performance history, including tests, so that planning and operational reliance reflects what resources actually deliver rather than nameplate or enrolled capability;
2. Portfolio diversification across devices, technologies, and customers, which smooths individual-resource variability (e.g., EV plug-in behavior, thermostat overrides);
3. Availability verification through telemetry or meter data appropriate to the service;
4. Seasonal and temporal availability profiles reflecting observed customer behavior; and
5. Conservative planning assumptions until a sufficient performance record is established, with dependable-contribution values updated as pilot and program M&V data accumulate.

Because the DSO remains responsible for safe and reliable operation, each program should also identify the remedial solution that preserves reliability if orchestrated DERs underperform – one of the application content elements SDG&E has proposed for the Framework.[49]

[48] SDG&E Opening Comments at 8-9, 17-18; SDG&E Workshop 1 Presentation, Slides 8, 13.

[49] SDG&E Workshop 1 Presentation, Slide 8.

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?

As of the date of this filing, SDG&E has not identified any promising programs under which DERs would be dispatched to defer or avoid planned circuit upgrades. This exact concept has already been tested via the now-discontinued DIDF. The DIDF demonstrated that distribution deferral is challenging for several reasons. One of the biggest challenges is the uncertainty of future distribution needs, and this uncertainty increases exponentially with time. So, while utilities can identify circuit-level needs over a ten-year planning horizon, it does not make sense to undertake financial commitments for the solutions to those needs until required by distribution upgrade lead times. Since most distribution solutions can be implemented within a three-year period, and since the process of assembling and testing a portfolio of DERs adequate to defer a planned upgrade on a specific distribution circuit can be lengthy (and may not even be possible), there are few commercially attractive deferral opportunities. Higher compensation levels can offset some of the commercial risks associated with assembling circuit-level DER portfolios on short notice, but if the compensation exceeds the deferral value, ratepayers would be better off if the utility proceeds with the upgrade.

DER technology and costs are always changing. In particular, SDG&E notes that electric vehicle technology may provide DER Orchestration opportunities that were not readily available at the time of the DIDF. If new circumstances support the development of programs under which circuit-specific DERs can be cost-effectively dispatched to defer planned distribution upgrades, and if underlying service contracts have been signed and the DER dispatch successfully tested, then the planned investments will not appear in future planning cycles for the years covered by the deferral contract.

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 Process (DPEP) and how would that be accomplished?

EPIC 4.08 is PG&E's pilot, and SDG&E defers to PG&E regarding its results, status, and ongoing development. To the extent this pilot is targeted at system-level impacts, the IEPR is the appropriate forum for considering the impacts of load flexibility on forecast loads. As SDG&E understands the CEC forecast methodology, forecast impacts from Commission-approved and funded demand response programs will be incorporated in IEPR's system-level load forecasts. These forecasts are then used in the DPEP and will therefore be reflected in distribution needs and the resulting planned distribution upgrades.

It is less clear how the pilot's circuit-level impacts could be used in the DPEP, but it is possible that they would be useful for disaggregating the system-level impacts to individual circuits. The disaggregation of system-level demand response impacts is necessary for the circuit-level DPEP analysis.

Given the CEC's requirement that any demand response program needs to be approved and funded before it is included in the IEPR load forecast, an early step is the design and submission of potential demand response programs to the Commission. In its earlier comments SDG&E proposed that the Commission initially develop a framework that would be used to evaluate specific-program applications that utilities would submit following the Commission's adoption of a framework. These applications would presumably include demand response programs that the utilities propose as an outcome of promising demand response pilots. Once the Commission approves those programs, the CEC will incorporate the projected impacts in the IEPR system-level forecast and the utilities can use pilot results to disaggregate the system-level results to individual circuits. The resulting circuit-level load forecasts will then be used in the DPEP and, in that way, the impact of demand response is reflected in distribution needs and the solutions to those needs.

SDG&E is confident that the CEC will incorporate demand response in its IEPR forecast only to the extent the impacts are considered to be dependable. Theoretical potential may be the starting point, but it will not be the amount that gets included in the forecast.

Procedurally, SDG&E recommends that EPIC 4.08 learnings be shared on the record – through the Track 2 working group and the DPEP/DPP forums – so that each utility can evaluate their applicability to its own system, data environment, and tools. The Commission should permit utility-specific adaptation of any resulting load forecasting methodology rather than mandating a single approach derived from one utility's pilot.

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?

SDG&E proposed in its opening comments that "safe and reliable grid operation" be added as a guiding principle, because it is fundamental to all DER orchestration approaches; the utility remains responsible for grid safety and reliability, with no exception for grid operations that use DERs as the vehicle for providing distribution services.[50] Building on that principle, the Framework should include the following components:

1. A clear definition of the DSO's role. Orchestration does not mean the utility has control over every DER at all times. It means the DSO identifies where and when grid services are valuable; communicates the timing, quantity, and attributes of needed services (e.g., via dispatch schedules) to the DER owner or its aggregator; and verifies performance and enforces applicable requirements pursuant to tariffs, programs, or contracts;[51]
2. Application content standards ensuring every program is anchored to reliability. Each program should identify the grid need to be mitigated; the conventional solution baseline; compensation where necessary; estimated costs and benefits; the DER performance attributes required; how performance will be measured; and – critically for this question – the remedial solution in the event of DER non-

[50] SDG&E Opening Comments at 9; SDG&E Reply Comments at 5 (citing Cal. Pub. Util. Code § 399.2(b)).

[51] SDG&E Opening Comments at 4.

performance, which is the component that preserves safe and reliable operation when orchestrated resources underperform;[52]

3. Fit-for-purpose visibility standards, matching the required visibility, latency, and granularity to the specific grid service rather than imposing a universal standard;
4. Readiness criteria ensuring that a utility dispatches DERs for a given service only when the necessary operational capabilities, tools, and verification mechanisms are in place;
5. Open access and transparent procurement, so that any provider willing and able to comply with the terms of the tariff and/or contract under which services will be delivered, can compete to meet identified needs;
6. Cybersecurity and privacy requirements governing data exchange between the utility and DER owners or aggregators;
7. The cost recovery architecture described in response to Question 6; and
8. Procedures for updating the Framework as operational experience accumulates.

The flexibility the question asks about is preserved by what the Framework deliberately leaves open: technology, protocol, and architectural choices remain implementation decisions; dispatch approaches (dynamic operating envelopes, contracts, real-time versus scheduled dispatch) are driven by grid needs and program design rather than mandates; and the Framework itself can be refined in proceedings reviewing utility proposals as experience develops.[53]

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.

SDG&E's record on this question has been deliberately measured. At present, opportunities for DERs to provide distribution services appear limited at compensation levels that would both induce DER-owner participation and provide overall ratepayer benefit.[54] With that context, SDG&E offers the following explicit examples:

[52] SDG&E Workshop 1 Presentation, Slide 8.

[53] SDG&E Opening Comments at 9; SDG&E Reply Comments at 8-9; SDG&E Workshop 1 Presentation, Slide 13.

[54] SDG&E Opening Comments at 4-5.

1. **WDAT charging limits (operational today).** Storage devices interconnecting under SDG&E's Wholesale Distribution Access Tariff can accept limits on device charging to avoid the costs of otherwise required upgrades. The DSO's role is limited to monitoring and enforcement. Since any storage device interconnecting under the WDAT can accept these limits, the opportunity scales with interconnection volumes.[55]
2. **Rule 21 Limited Generation Profiles (operational today).** Generators can elect the LGP interconnection option – limiting exports during designated periods using customer-provided control technology – to avoid the costs of otherwise required distribution upgrades. The DSO's role is monitoring and enforcement.[56]
3. **Targeted deferral of planned distribution upgrades.** The DIDF experience suggests that commercially viable deferral opportunities at ratepayer-beneficial compensation levels have been limited to date. However, the DER landscape is evolving: increasing numbers of V2G-capable EVs and growing battery density may create cost-effective opportunities not previously available. Such programs should be piloted first, and compensation should be limited to DERs that are in the right place, at the right time, in the right quantity, and with the right performance characteristics to provide the needed distribution service.[57]
4. **Improved TSO-DSO coordination and data sharing.** As discussed at Workshop 2, improved forecast accuracy and situational awareness can reduce the need for conservative operational actions, improve market efficiency, and enable better utilization of lower-cost demand flexibility – benefits that accrue at the system level and grow as data exchange and forecasting capabilities mature. Such data sharing should nonetheless be subject to cost-benefit assessments and targeted pilots, where the benefits mentioned above are actually realizable and clearly offset the cost the DSO incurs to provide the data.[58]

[55] SDG&E Opening Comments at 7.

[56] SDG&E Opening Comments at 6-7.

[57] SDG&E Opening Comments at 5-6, 12-13; SDG&E Reply Comments at 11-12.

[58] Workshop 2 Report at 4 (CAISO affordability discussion); SDG&E Workshop 2 Presentation, Slides 14, 16.

5. **Speed-to-power/bridging solutions, where a need exists.** Partial energization of new load pending completion of required upgrades can avoid customer delay costs, support electrification and reduce ratepayer costs through increased utility revenues (without partial load energization there would be no increased revenues). PG&E and SCE are already implementing such solutions; SDG&E has not to date had a need to employ them on its system.[59]

How these opportunities shift between initial implementation and scaling: at initial implementation, fixed enablement costs – DERMS and platform costs, telemetry and communications, settlement and administration, M&V, customer acquisition, and any device-signaling licensing fees – suggest a limited set of viable opportunities. Many potential services will not be cost-effective. With scaling, fixed costs are spread over more transactions, portfolio diversification improves dependability, and enrollment and integration costs per DER resource decline. But scaling also introduces its own cost pressures: manufacturer licensing fees have continued to rise, aggregator margins and customer compensation are recurring costs, and paying broad aggregations in advance of identified needs creates a high probability of paying for services that are never used. For these reasons, demonstrated cost-effectiveness should be a threshold requirement before scaling, and compensation discipline.[60]

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?

SDG&E identifies five issues raised in or underscored by the workshops that the Commission should address in designing the application process:

1. **The demand response interface.** There is significant overlap between the Commission's vision for DER orchestration and its requirements for DR programs, and the new DR rulemaking (R.25-09-004) that is likely to delay the next filing of DR applications until 2029 for implementation in 2030. The Commission should clarify which regulatory vehicle governs programs – such as V2G – that could plausibly proceed under either construct, and how cost-

[59] SDG&E Opening Comments at 6; SDG&E Reply Comments at 6.

[60] SDG&E Opening Comments at 13, 15; SDG&E Reply Comments at 7-8, 11-12.

effectiveness protocols will apply and be updated so that distribution-level benefits are fully captured.[61]

2. **The device-signaling business model.** Workshop 1 discussion reinforced that manufacturer licensing fees, closed vendor ecosystems, standards that lack implementation specificity, and legacy devices with no participation pathway are structural constraints on orchestration. Resolving them is largely outside the control of the IOUs or the Commission, and likely requires legislative action and/or codes-and-standards changes within California; in the interim, these costs must be counted in cost-effectiveness analysis.[62]
3. **TSO-DSO coordination sequencing.** The CAISO's Operational Coordination Framework – developed through its Industry Expert Working Group with phased implementation planned between 2026 and 2030 – is the appropriate forum for detailed use-case development, data-exchange design, and **forecasting** alignment at the transmission-distribution interface. Commission processes in this proceeding should complement and remain informed by that work rather than prescribing what should be done. SDG&E suggests the CAISO provide the Commission with periodic progress updates which get included in this record. Consistent with SDG&E's Workshop 2 presentation, coordination investments should be anchored in clearly defined operational challenges, minimum viable data standards, and demonstrated customer value.[63]
4. **DSO-side data gaps.** The Workshop 2 open discussion identified that DSOs currently lack access to non-IOU load-serving entity load forecasts, to data on DERs participating in non-IOU programs, and data on third-party DERs participating directly in the CAISO wholesale market – leaving DSOs with an incomplete view of system conditions that constrains forecasting and operational awareness as well as a limited picture of resources to call upon. It is true that the DSOs/IOUs could begin to anticipate how orchestration could work, with only partial data. It is not clear what the full value of that exercise would be. For

[61] SDG&E Opening Comments at 13-14; SDG&E Workshop 1 Presentation, Slide 25.

[62] SDG&E Opening Comments at 13, 16; Workshop 1 Report at 6, 9.

[63] Workshop 2 Report at 5-6; SDG&E Workshop 2 Presentation, Slide 14.

example, while the ADMS/DERMS can estimate DER impacts from historical or real-time measurements, forecast accuracy improves when dispatch schedules or planned operating profiles are available. The Commission should consider whether and how data-sharing obligations should be expanded to close these gaps, with appropriate attention to confidentiality, privacy, costs/benefits and implementation feasibility. Data visibility should flow in both directions between the CAISO and the DSOs.[64] But the DSO will need more complete data to make that process accurate and fully useful. Additionally, the costs of storing more data provided to the DSOs will need appropriate cost recovery.

5. **Organizational and affiliate separation constraints.** As SDG&E noted at Workshop 2, organizational and affiliate separation requirements limit the information that IOU transmission and distribution operations are **allowed** to share with the IOU's market dispatch functions, which can create coordination and forecasting challenges. Coordination framework design should account for these constraints.[65]

Finally, SDG&E reiterates that if the Commission directs or requires utility action in connection with the application process, it must also address how that action will be funded, recognizing whether existing funding is adequate and, if not, providing a dedicated cost recovery mechanism.[66]

III. CONCLUSION

The workshops confirmed both the promise of DER orchestration and the substantial foundational work that remains. The Commission should complete that work in the proper sequence: adopt a durable DER Orchestration Framework in Track 2 – developed through a Commission-led working group and/or structured workshops with written party comments – that establishes the guiding principles (including safe and reliable grid operation), cost-benefit methodology, performance metrics and M&V standards, pilot evaluation and progression criteria, participation-model standards, readiness criteria, and cost recovery architecture against which all subsequent utility proposals will be evaluated. Applications should then be optional

[64] Workshop 2 Report at 13-14.

[65] Workshop 2 Report at 9.

[66] SDG&E Reply Comments at 9.

and readiness-driven, filed when a utility has identified cost-effective opportunities and developed the operational capability to deliver, with pilots serving as the necessary bridge from technical promise to implementation at scale.

Throughout, the Commission's central focus should remain on safe and reliable grid operation and on ensuring that orchestration is pursued only where there is a demonstrated distribution need and a strong likelihood of net ratepayer benefit. The Framework should remain technology-neutral – leaving protocols, architectures, and dispatch designs as utility implementation choices – and should be paired with adequate cost recovery for any Commission-directed action, clarity on the demand response interface, and continued coordination with the CAISO's Operational Coordination Framework on transmission-distribution issues. SDG&E is committed to continued collaboration with the Commission, the CAISO, and stakeholders to advance DER orchestration in a manner that is technically sound and prudent for ratepayers.

Respectfully submitted,

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