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 Filed June 24, 2021

JOINT OPENING COMMENTS OF CLEAN COALITION, CENTER FOR BIOLOGICAL DIVERSITY, 350 BAY AREA, VOTE SOLAR, THE CLIMATE CENTER, AND MICROGRID RESOURCES COALITION ON THE PROPOSED DECISION REGARDING DER ORCHESTRATION AND LOAD FLEXIBILITY SCENARIOS

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October 19, 2026

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RECOMMENDED CHANGES TO THE PROPOSED DECISION

The Joint Parties request that the Commission amend the Proposed Decision's Findings of Fact, Conclusions of Law, and Ordering Paragraphs, as detailed in Appendix A, to:

1. **Establish enforceable, competitively neutral governance requirements.** Require open and nondiscriminatory DER participation, independent oversight, decision-grade data access, and safeguards against utility self-preference in market participation, procurement, dispatch, and infrastructure investment decisions. These requirements should apply regardless of the ultimate DSO governance structure.
2. **Establish a Commission-supervised, two-phase working group process.** Require Energy Division supervision of stakeholder participation, facilitation, and reporting. Phase 1 would address governance, market access, competitive neutrality, data access, and utility incentive structures, including shared-savings and international approaches, with an interim report due within 120 days. Within 60 days thereafter, the Commission would establish minimum governance requirements. Phase 2 would develop valuation, cost-effectiveness, dispatch, interoperability, and implementation recommendations consistent with those requirements. Preserve stakeholder review and non-consensus recommendations, and extend the Joint IOU Application deadline to 14 months.
3. **Require open, interoperable, and technology-neutral participation pathways.** Ensure that CCAs, aggregators, customers, and independent DER providers can deliver grid services through interoperable communication systems, reasonable performance requirements, appropriate data access, and nondiscriminatory compensation and dispatch mechanisms. Address proprietary barriers, unreasonable integration costs, and unnecessary duplication of existing utility technology investments.
4. **Require valuation and cost-effectiveness assessments at both the use-case and DER portfolio levels.** Evaluate the combined capabilities, dependable capacity, availability, dispatchability, performance, and full incremental costs of coordinated DER portfolios using service-appropriate, technology-neutral criteria.
5. **Recognize the full range of distinct, nonduplicative DER services and benefits.** Require consideration of applicable energy, capacity, distribution, transmission-related, resilience, reliability, environmental, electrification, energization, and operational

benefits. Allow resources and portfolios to provide multiple distinct grid services while preventing double counting or compensation for the same benefit.

6. **Establish comprehensive statewide valuation and cost-effectiveness requirements.** Require the IOUs to demonstrate how the ACC, LNBA, or supplemental methodologies capture relevant locational, temporal, and stacked benefits. Consider the Total Resource Cost test and appropriate societal analyses alongside net ratepayer impacts, rather than relying solely on narrow rate-impact measures.
7. **Integrate EIS Part 2 findings into proactive distribution planning.** Expressly recognize the study's substantial modeled infrastructure cost-reduction potential and require Load Flexibility Scenario results to identify candidate locations where DER portfolios should be evaluated against traditional infrastructure solutions early enough to influence investment decisions. Include disadvantaged and environmental and social justice communities, with appropriate project-specific validation and tracking.
8. **Require measurable savings realization and accountability.** Direct the IOUs to develop a savings-realization plan identifying how DER alternatives will be screened, pursued, procured, measured, and reported. Track avoided, deferred, or right-sized distribution investments and other net ratepayer benefits, consistent with Public Utilities Code § 769.
9. **Preserve and resolve outstanding Track 2 governance and data-access issues.** Ensure that unresolved matters, including the CBD/UCAN Motion to Address Unaddressed Issues and Clean Coalition's Motion to Compel, receive an express procedural disposition and that outstanding governance safeguards are not treated as resolved merely through referral to the working group or Joint IOU Application.

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I. INTRODUCTION

Pursuant to Rule 14.3 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, Clean Coalition, Center for Biological Diversity, 350 Bay Area, Vote Solar, The Climate Center, and Microgrid Resources Coalition ("Joint Parties") submit comments on the *Proposed Decision* ("PD") *Adoption an Application Process for Utility Distributed Energy Resources* ("DER") *Orchestration and Ordering Utilities to Incorporate Load Flexibility Scenarios into Their Distribution Planning and Execution Processes* ("DPEP"), issued by the Commission on September 25, 2026, and the October 6, 2026, *Procedural Email Confirming R. 21-06-017 Tracks 1 and 2 Comment Due Dates*.

The Joint Parties support the PD's movement toward implementing DER orchestration and Load Flexibility Scenarios. The Commission's recognition of the locational and temporal value of DER, the importance of open access to the distribution grid, the need for interoperability, and the potential for substantial ratepayer savings through effective DER orchestration represents a significant step forward. The PD requires an investor-owned utilities ("IOU") to file a Joint DER Orchestration Application, adopts initial guiding principles, establishes a pre-application working group to address key issues, and requires the utilities to incorporate a new Load Flexibility scenario in the DPEP.

However, the PD does not yet provide the foundation necessary to ensure those processes produce an open, competitively neutral, value-based DER orchestration framework rather than a framework that artificially constrains opportunities for savings. Although the PD recognizes the importance of competitive neutrality and appropriate Commission oversight, it expressly declines to prescribe a governance model and leaves foundational market-design questions to the

Joint IOU Application without first establishing adequate minimum governance requirements.[1] Similarly, although the PD acknowledges that DER can provide distinct locational, temporal and infrastructure-related benefits, and requires the IOUs to justify valuation methodologies for individual use cases,[2] it stops short of requiring full, nonduplicative value stacking and portfolio-level valuation and cost-effectiveness assessment. Finally, the PD acknowledges the substantial potential distribution infrastructure savings identified in the Electrification Impacts Study ("EIS") Part 2 and orders development of a Load Flexibility Scenario, but fails to establish a clear, enforceable pathway from those findings to actual infrastructure-planning decisions and measurable cost reductions. Together, these omissions risk leaving significant ratepayer savings on the table.

Without clear requirements, DER orchestration risks becoming a technologically sophisticated version of the Distribution Investment Deferral Framework ("DIDF"): IOUs continue designing traditional infrastructure upgrades and then evaluate narrowly defined DER use cases as potential deferrals of already-planned investments. Such an approach could overlook the greater opportunity to identify where distributed flexibility can avoid or right-size infrastructure investments before they are designed, or accelerate customer energization. Moreover, a narrowly defined use case may appear unreliable or uneconomic when evaluated as a single technology providing a single service, even where a diversified DER portfolio could dependably address the same grid need while delivering additional, distinct benefits. These risks are particularly consequential because IOUs earn an authorized return on rate-based infrastructure investments, creating a structural financial incentive that requires Commission oversight and accountability. Requirements for identifying locations where DER flexibility can provide value, fairly evaluating DER portfolios and their full value stack, and measuring actual infrastructure cost reductions are essential for determining how much of the savings potential identified in EIS Part 2 can be achieved and ultimately realized. Absent these safeguards, the Commission risks establishing a DER orchestration framework that evaluates alternatives to

[1] PD, at p. 40. ("the Commission declines at this stage to prescribe a particular structure or governance model.")
[2] *Ibid*., at p. 27. ("The Commission also agrees with SDG&E and UCAN that valuation should account for locational benefits and differentiate, where applicable, between broader system-level benefits and location-specific distribution system benefits. Measurable, avoided, or deferred infrastructure costs and operational benefits should also be reflected where applicable, including the potential for DER orchestration to affect the need, timing, or sizing of traditional distribution investments.")

traditional infrastructure without fundamentally changing the investment decisions that drive ratepayer costs.

These concerns are not new arguments raised for the first time in response to the PD. The Commission's August 11, 2023 Amended Scoping Memo expressly identified limiting market power, reducing ratepayer costs, supporting grid resiliency, advancing State policy objectives, and overcoming barriers within the existing IOU-operated DSO as foundational Track 2 issues.[3] The subsequent Future Grid Study identified unresolved questions concerning DSO/CAISO coordination, grid-services market development, diverging DSO visions, and data sharing and transparency.[4] The 2026 Commission-led workshops and subsequent party comments further developed these issues through concrete proposals for open participation, competitive neutrality, grid-services valuation, value stacking, data access, and evaluation of DER portfolios against traditional infrastructure alternatives.[5] In parallel, EIS Part 2 demonstrated substantial potential distribution infrastructure savings from demand flexibility, reinforcing the importance of integrating DER capabilities into distribution planning.[6] Although the PD acknowledges much of this record, its Findings of Fact, Conclusions of Law, and Ordering Paragraphs do not adequately translate that record into enforceable governance, valuation, and planning requirements. The Joint Parties seek to correct that disconnect, not introduce a new regulatory framework.

The Commission need not prescribe a particular DSO governance model or a single valuation methodology to correct these deficiencies. Indeed, the PD already demonstrates that the Commission can establish enforceable statewide requirements without prematurely determining implementation details. Its treatment of interoperability requires open, standardized approaches while allowing justified deviations. The same approach should apply to foundational governance, market access, data-sharing, and valuation requirements before the IOUs develop their Joint Application. Therefore, the Joint Parties request that the Commission establish minimum governance requirements that ensure open and nondiscriminatory participation, independent oversight, transparent data access, and safeguards against utility self-preference. These safeguards must address both the IOUs' financial incentives to favor traditional infrastructure investments over cost-effective DER alternatives and the potential preference for utility-

[3] *Ibid*., at p. 8.
[4] *Ibid*., at p. 9.
[5] *Ibid*., at pp. 10-11.
[6] *Ibid*., at pp. 57-60.

controlled resources over independent DER providers. They should also require transparent identification of grid needs and competitively neutral evaluation of DER portfolios against traditional infrastructure solutions. Likewise, minimum statewide valuation requirements should encompass the distinct, measurable, and nonduplicative energy, capacity, distribution, transmission-related, resilience, emissions, electrification-support, energization, and operational benefits relevant to each DER resource or portfolio. Finally, the Commission should require EIS Part 2 findings to inform distribution planning through identification of candidate locations, evaluation of DER portfolios before traditional infrastructure investments are selected, and measurable accountability for the resulting infrastructure cost reductions.

Accordingly, pursuant to Rule 14.3, the Joint Parties request targeted revisions to the PD's Findings of Fact, Conclusions of Law, and Ordering Paragraphs, as set forth in Appendix A. Section II addresses the need for enforceable governance requirements and a Commission-supervised, two-phase working group, with an initial governance report informing a Commission determination of minimum requirements before the Joint IOU Application. Section III addresses the minimum valuation and cost-effectiveness requirements necessary to recognize DER portfolios and their full, nonduplicative value stack. Section IV addresses integration of EIS Part 2 into distribution planning and the accountability measures necessary to translate potential infrastructure savings into measurable results.

II. THE COMMISSION MUST ESTABLISH FOUNDATIONAL GOVERNANCE REQUIREMENTS BEFORE IOU APPLICATION

A. The PD Must Establish Enforceable Governance Safeguards Before the IOUs Develop Their Framework

The PD correctly recognizes that guiding principles must be established upfront to create consistency and protect public policy interests during development of the Joint IOU DER Orchestration Application.[7] However, while the PD adopts 11 guiding principles, it leaves foundational governance and market-design requirements largely to an IOU-contracted working group and the subsequent Joint IOU Application. This approach would allow the IOUs to develop both their proposed orchestration framework and many of the standards against which it will ultimately be evaluated. This omission is particularly significant because the PD expressly recognizes that guiding principles must be established upfront, yet its treatment of governance in

[7] *Ibid*., at pp. 21-22.

Section 6.3 and Ordering Paragraph 28 leaves the development of competitive-neutrality and oversight safeguards to the Joint IOU Application, without establishing minimum enforceable standards against which those proposals must be evaluated.[8] These concerns were expressly anticipated in the Order Instituting Rulemaking, where the Commission recognized that existing utility cost-recovery structures favor capital investments and that alternative incentives or DSO administration may be necessary to support a high-DER future.[9] The Commission should revise the PD and instead establish enforceable minimum requirements that provide a consistent basis for stakeholder participation, application development, and Commission review.

The existing principles are an important starting point, but they do not adequately address the structural conflicts of interest inherent in an IOU-operated DSO framework. Utilities have financial incentives to pursue rate-based infrastructure investments, while IOU control over grid information, market access, and operational decisions also creates opportunities to favor utility-managed resources over independent providers. Minimum governance requirements must therefore ensure open and nondiscriminatory participation, competitive neutrality, independent oversight, decision-grade data access, and transparent identification of grid needs. These safeguards should apply not only to participation and dispatch, but also to decisions about whether DER portfolios can cost-effectively avoid, defer, or right-size traditional infrastructure investments.

Establishing these requirements does not require the Commission to select a particular DSO organizational structure. Rather, it requires the Commission to define the minimum standards that any proposed structure must satisfy. The Joint Parties therefore recommend strengthening the adopted guiding principles and requiring the Joint IOU Application to demonstrate compliance with enforceable governance and competitive-neutrality safeguards, as reflected in Appendix A.

B. The Commission Must Oversee a Two-Phase Working Group and Establish Governance Requirements Before the Joint IOU Application

Although Section 4.2.1 and Ordering Paragraphs 2–3 establish a pre-application working group with stakeholder participation and reporting requirements,[10] the PD does not require the

[8] *Ibid*., at p. 40.
[9] R. 21-06-017, *Order Instituting Rulemaking* (June 24, 2021), at pp. 11–12.
[10] PD, at pp. 23–25, pp. 85–86.

Commission to adopt minimum governance standards based on that process before the IOUs finalize their proposed framework. Instead, the working group report becomes an input to the Joint IOU Application, leaving the IOUs substantial discretion over how competing recommendations are incorporated. The Joint Parties therefore recommend restructuring the pre-application working group into two phases under Energy Division supervision, with Phase 1 culminating in a report that informs a Commission determination establishing minimum governance requirements before the Joint IOU Application is finalized. Energy Division should oversee the facilitator, stakeholder participation, working-group agenda, and preparation of reports to ensure that stakeholder recommendations are fairly represented and that the process is not controlled by the entities whose proposals will ultimately be evaluated.

Phase 1 should address governance principles, market-participant roles, competitive neutrality, data access, independent monitoring, and minimum application requirements. It should also review relevant international DSO governance and incentive approaches, including those adopted in Great Britain and Australia, to inform California's consideration of oversight, performance accountability, and incentives for cost-effective DER alternatives.[11] The Phase 1 interim report should identify proposed requirements, areas of stakeholder agreement and disagreement, and alternative recommendations for Commission consideration.

Critically, the Phase 1 report must lead to a Commission determination of minimum governance requirements before the IOUs finalize their framework and file the Joint IOU Application. Otherwise, the working group risks becoming another advisory process whose recommendations can be selectively incorporated into IOU proposals without binding Commission direction. Phase 2 should then develop the valuation, cost-effectiveness, dispatch, interoperability, and implementation details consistent with the Commission's minimum governance requirements, while preserving stakeholder opportunities to review and comment on the resulting recommendations.

The need for a Commission determination before the Joint IOU Application is also reflected in the unresolved governance questions raised by the Center for Biological Diversity and Utility Consumers' Action Network in their September 10, 2026 Motion to Address Unaddressed Issues,

[11] R. 21-06-017, Assigned Commissioner's Ruling on Track 1 and Track 2 Distributed Energy Resources Orchestration (March 23, 2026), at p. 8, Questions 6–7 (seeking comments on shared-savings mechanisms and DSO incentive structures in the United Kingdom and Australia, neither of which is expressly resolved in the PD).

which Clean Coalition, 350 Bay Area, and Vote Solar supported. The Motion requests further consideration of whether existing utility investment and cost-recovery incentives undermine cost-effective DER orchestration and what safeguards are necessary to address those conflicts. Similarly, the March 23, 2026 Assigned Commissioner's Ruling expressly sought input on shared-savings mechanisms and regulatory incentive structures in other jurisdictions, issues that the PD does not substantively resolve. The Commission should therefore preserve Track 2 for a determination of these outstanding governance and incentive-alignment questions, rather than treating referral to the working group or Joint IOU Application as sufficient to resolve them.

The Joint Parties request that the Commission revise the working-group structure, establish an appropriate schedule for a substantive governance determination, and require the Joint IOU Application to demonstrate compliance with the resulting requirements, as detailed in Appendix A.

III. THE COMMISSION MUST ESTABLISH MINIMUM VALUATION AND COST-EFFECTIVENESS REQUIREMENTS THAT RECOGNIZE DER PORTFOLIOS AND THEIR FULL VALUE STACK

The PD appropriately recognizes that DER orchestration valuation should reflect specific grid needs, location, timing, and measurable benefits. However, while the PD repeatedly requires use-case-specific valuation, it does not establish comparable requirements for assessing the combined capabilities, costs, and benefits of DER portfolios. This omission risks understating the economic potential of coordinated DER resources. The Commission should therefore establish three minimum requirements: portfolio-level evaluation, recognition of multiple distinct services and benefits, and comprehensive, nonduplicative valuation methodologies.

A. The PD Must Explicitly Require Portfolio-Level Valuation Within Its Use-Case Framework

The PD appropriately requires the IOUs to evaluate the costs and benefits of DER orchestration at the use-case level, as reflected in Section 5.1, Conclusions of Law 3 and 14, and Ordering Paragraphs 10 and 15.[12] However, these requirements do not expressly direct the IOUs to evaluate the collective capabilities, dependable capacity, and cost-effectiveness of coordinated DER portfolios. This omission is inconsistent with the PD's recognition that aggregators can

[12] PD at pp. 29–32, pp. 77–80, and pp. 87–89 (Section 5.1; Conclusions of Law 3 and 14; Ordering Paragraphs 10 and 15).

coordinate DER resources to provide grid services and that DER portfolios can reduce or defer distribution infrastructure upgrades.[13] Acknowledging these capabilities without requiring their evaluation leaves a significant gap in the valuation framework.

A use case identifies a particular grid need or service, whereas a DER portfolio combines resources capable of meeting that need. Such portfolios may consist of similar resources or complementary technologies whose combined availability, duration, dispatchability, and performance can provide dependable grid services that individual resources cannot deliver independently. Although the PD's use-case-specific approach does not preclude portfolio evaluation, it does not ensure that the IOUs will assess these combined capabilities. Consequently, DER portfolios capable of satisfying grid needs cost-effectively could be overlooked or undervalued simply because their constituent resources cannot individually satisfy the same requirements.

Accordingly, the Joint Parties recommend that the Commission expressly require valuation and cost-effectiveness methodologies to assess the combined capabilities, costs, and benefits of DER portfolios within applicable use cases. These evaluations should apply transparent, technology-neutral performance, reliability, availability, dispatchability, and verification criteria appropriate to the grid service provided, including the combined capabilities of the portfolio, and account for the full incremental costs of coordinating and operating the portfolio. Where DER portfolios are compared with traditional infrastructure alternatives, the analysis should use equivalent assumptions regarding reliability, timing, performance, risk, and total costs and benefits. These requirements would ensure that portfolio-level solutions receive fair consideration without presuming that aggregation is always preferable to individual resources or traditional infrastructure.

B. The PD Must Explicitly Recognize the Full Range of Distinct Services and Benefits Provided by DERs

A central advantage of DER orchestration is that a single resource or portfolio may provide multiple distinct grid services, increasing its value to the grid and ratepayers beyond any one application. For example, distributed storage and flexible loads may shift consumption in

[13] *Ibid*., at pp. 36–38 and p. 61 (Section 6.2, *Role of DER Aggregators Within a Proposed Framework*, and Section 8.3.1, discussing candidate locations where DER portfolios can reduce or defer infrastructure upgrades).

response to price signals, provide targeted distribution capacity during locally constrained hours, and support broader system reliability under different operating conditions. Each service may address a different grid need, at a different location or time, with different performance obligations and economic benefits. Failing to recognize these distinct contributions can understate the total value of DER orchestration and potentially exclude resources or portfolios that would otherwise be cost-effective.

The PD's treatment of grid services and valuation does not fully reflect this opportunity. Section 3.2 and Ordering Paragraphs 5–6 identify services such as reliability, outage mitigation, infrastructure deferral, and electrification support, while Section 5 requires valuation of measurable infrastructure and operational benefits.[14] The PD also requires protections against double payment or double counting,[15] but does not establish a corresponding requirement to recognize multiple distinct, nonduplicative benefits delivered by the same resource or portfolio. This omission is particularly significant given that the PD itself acknowledges Clean Coalition's recommendation that distributed storage be considered as part of a broader value stack of grid needs.[16]

Transmission-related benefits provide one example of this gap. Although the PD directs continued TSO–DSO coordination with CAISO,[17] it does not expressly require evaluation of whether DER orchestration can improve transmission utilization, reduce congestion, or avoid or defer transmission investment where supported by system analysis. Similarly, the PD recognizes reliability, outage mitigation, and the potential for DER portfolios to improve resilience, without expressly requiring assessment of distinct resilience benefits in its valuation directives. The PD also acknowledges that DER orchestration can accelerate customer energization, even while addressing other speed-to-power issues in separate proceedings.[18] These benefits should not be excluded from consideration simply because they extend beyond the immediate distribution service motivating a particular DER use case.

The Joint Parties therefore recommend that the Commission expand its recognized grid services and valuation requirements to encompass all applicable, distinct, measurable, and

[14] *Ibid*., at pp. 16-17, and p. 86 (Section 3.2; Ordering Paragraphs 5–6).
[15] *Ibid*., at p. 41, and p. 86 (Section 6.3; Conclusion of Law 12).
[16] *Ibid*., at p. 71 (Section 8.3).
[17] *Ibid*., at p. 36, 88, and 91 (Section 6.1 and Ordering Paragraphs 13 and 24).
[18] *Ibid*., at p. 15, pp. 30–31, and p. 61.

nonduplicative benefits of DER resources and portfolios. This includes distribution, transmission-related, resilience, electrification-support, energization, environmental, and operational benefits. Such requirements would not presume that every resource provides every benefit or permit double counting. Rather, they would ensure that the Joint IOU Application evaluates the full range of services DER orchestration can provide, establishing the foundation for comprehensive valuation and cost-effectiveness methodologies.

C. Valuation and Cost-Effectiveness Methodologies Must Capture the Full, Nonduplicative DER Value Stack

Recognizing additional grid services and benefits will not ensure accurate valuation unless the methodologies used to evaluate DERs can capture those benefits at the relevant locations, times, and levels of system operation. Section 5 of the PD acknowledges that the Avoided Cost Calculator ("ACC") may need to be combined with other methods to quantify granular locational value, and the record includes support for the Total Resource Cost ("TRC") and Societal Cost Test ("SCT") as means of capturing broader benefits.[19] Moreover, D.19-05-019 establishes the TRC as the primary cost-effectiveness test for applicable DER evaluations, while D.24-07-015 adopts the SCT as an additional, information-only test.[20] However, Conclusions of Law 11–14 and Ordering Paragraphs 10–15 primarily require the IOUs to propose and justify their selected methodologies, without expressly requiring comprehensive valuation of the full, nonduplicative value stack or consideration of broader cost-effectiveness perspectives.[21] As a result, even an expanded list of recognized grid services could leave significant DER value unaccounted for in cost-effectiveness assessments.

The Joint Parties therefore recommend minimum statewide valuation requirements without prescribing a single valuation tool or cost-effectiveness test. The IOUs should demonstrate how their proposed methodologies account for the location, timing, duration, frequency, and persistence of grid needs and capture applicable energy, capacity, transmission, distribution, operational, resilience, environmental, and other distinct, nonduplicative benefits. The IOUs should identify which benefits are captured by the ACC, Locational Net Benefits Analysis, or other selected tools, and propose supplemental methods where necessary. Cost-effectiveness

[19] *Ibid*., at pp. 28–29 (ACC and supplemental locational valuation methodologies) and pp. 30–31 (EDF and 350 Bay Area support for TRC and SCT).
[20] D.19-05-019, at pp. 2–3; D.24-07-015, at pp. 23–24.
[21] PD, at pp. 79–80 and pp. 87-89. (Conclusions of Law 11–14 and Ordering Paragraphs 10–15).

assessments should recognize applicable benefits at both the use-case and portfolio levels, account for full incremental costs, and explain how the TRC and, where appropriate, SCT or comparable societal analyses can inform the assessment of broader net system value alongside net ratepayer benefits. Narrow rate-impact measures should not serve as the sole basis for excluding DER portfolios with broader net benefits. Where reliable monetary valuation is unavailable, the IOUs should transparently quantify benefits where feasible or assess them qualitatively rather than exclude them without explanation. These requirements would allow the Commission to evaluate the full economic potential of DER orchestration while maintaining rigorous, consistent, and transparent cost-effectiveness standards.

IV. THE COMMISSION MUST TRANSLATE THE EIS PART 2 FINDINGS INTO ENFORCEABLE DISTRIBUTION-PLANNING AND SAVINGS-REALIZATION REQUIREMENTS

The PD identifies substantial opportunities to reduce distribution infrastructure costs through demand flexibility. As discussed in Section 8.3, EIS Part 2 modeled approximately $1.8 billion in cost reductions for PG&E, $320 million to $1.38 billion for SCE, and $697 million for SDG&E through 2040, depending on the utility and scenario.[22] The PD expressly concludes that capturing demand flexibility in distribution planning is a significant affordability opportunity. Although these findings represent modeled potential rather than guaranteed savings, they demonstrate that DER orchestration can materially affect future infrastructure investment needs. The Commission should reflect this cost-reduction potential expressly in its Findings of Fact and establish requirements for converting it into measurable outcomes.

The PD takes an important step by requiring a Load Flexibility Scenario in the DPEP, including consideration of locational and temporal inputs, utility decision logic, and candidate DER investment locations in disadvantaged and environmental and social justice communities.[23] However, its Ordering Paragraphs do not expressly require DER portfolios to be screened and compared with traditional infrastructure alternatives early enough to influence investment decisions, nor do they establish a process for measuring the resulting cost reductions. Without these additional requirements, DER orchestration risks becoming an overlay on traditional infrastructure planning rather than a means of optimizing investments before they are selected.

[22] *Ibid*., at pp. 65–66 (Section 8.3.3)
[23] *Ibid*., at pp. 68–70 and pp. 94-96. (Sections 8.4 and Ordering Paragraphs 36–39)

The Commission should require the IOUs to identify candidate locations, evaluate dependable DER portfolios against traditional infrastructure solutions based on equivalent reliability, timing, performance, and cost-effectiveness requirements, and pursue viable alternatives through appropriate procurement and implementation pathways.

This approach is consistent with Public Utilities Code § 769, which requires distribution resource plans to evaluate the locational benefits and costs of DERs, identify tariffs, contracts, or other mechanisms for deploying cost-effective distributed resources, coordinate existing Commission-approved programs and incentives to maximize locational benefits and minimize incremental costs, and identify barriers and incremental utility spending necessary for DER integration.[24] The statute also directs the Commission to minimize overall system costs and maximize ratepayer benefits and expressly authorizes accountability mechanisms for investments made pursuant to distribution resource plans. SB 905 (Stats. 2026, ch. 986) further reinforces this approach by adding Public Utilities Code § 769.1(c), which will require utilities to assess whether improving grid utilization through load flexibility and distribution-connected storage can address identified distribution needs associated with future load growth at lower cost than traditional infrastructure upgrades.[25] The Joint IOU Application should therefore demonstrate how the proposed orchestration framework advances these existing statutory objectives rather than simply adding another layer of DER analysis to traditional planning.

The Joint Parties accordingly recommend that the Commission require a savings-realization plan in the Joint IOU Application, as proposed in Appendix A. The plan should establish how EIS Part 2 findings and Load Flexibility Scenario results will inform candidate-site identification, early evaluation of DER alternatives, procurement opportunities, performance verification, and infrastructure investment decisions. It should also specify how the IOUs will measure and report actual avoided, deferred, or right-sized distribution investments, operational cost reductions, and other net ratepayer benefits, accounting for the incremental costs of DER deployment and orchestration. Project-specific assumptions must be validated, and modeled savings should not be treated as realized benefits without verification. Nevertheless, uncertainty about individual projects does not justify failing to establish a systematic process for pursuing and measuring these opportunities. Without such accountability, the Commission risks

[24] Public Utilities Code § 769(b)(1)-(5), (c)–(d).
[25] SB 905 (2026), Chapter 986, § 3 (adding Pub. Util. Code § 769.1(c), effective January 1, 2027).

recognizing hundreds of millions of dollars in potential ratepayer savings without establishing how those savings will be achieved.

V. CONCLUSION

The record developed in R. 21-06-017 provides a substantially stronger foundation for DER orchestration than is presently reflected in the PD's Findings of Fact, Conclusions of Law, and Ordering Paragraphs. The Commission's scoping decisions, Future Grid Study, stakeholder workshops, party comments, and EIS Part 2 findings have established the importance of competitive neutrality, comprehensive DER valuation, integration with distribution planning, and the substantial potential for ratepayer savings. Although the PD recognizes many of these considerations, it does not consistently translate them into enforceable requirements. The Joint Parties' proposed amendments would close that gap by building upon the existing record and strengthening the framework the Commission has already begun to establish.

These amendments are complementary and necessary to achieving the PD's objectives. Minimum governance requirements and independent oversight would establish a fair foundation for DER participation and evaluation. Comprehensive, nonduplicative valuation would ensure that individual resources and coordinated portfolios are assessed based on their dependable capabilities and full range of applicable benefits. Integrating those evaluations into distribution planning before traditional infrastructure investments are selected, together with measurable savings-accountability requirements, would create a pathway for translating the substantial potential identified in EIS Part 2 into actual ratepayer benefits. Without these elements working together, DER orchestration risks remaining an additional layer of analysis rather than fundamentally improving how grid investments are evaluated and optimized.

The Joint Parties therefore respectfully urge the Commission to adopt the targeted revisions to the Findings of Fact, Conclusions of Law, and Ordering Paragraphs proposed in Appendix A. These amendments would not prescribe a particular DSO governance model, predetermine the outcome of cost-effectiveness evaluations, or assume that all modeled savings will be realized. Rather, they would establish the minimum safeguards, valuation standards, and implementation requirements necessary to give effect to the existing record and provide a more credible, transparent, and accountable foundation for DER orchestration that maximizes opportunities to reduce costs for California ratepayers.

Respectfully submitted,

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Dated: October 19, 2026

Appendix A: Changes to Findings of Fact, Conclusions of Law, and Ordering Paragraphs

Findings of Fact

1. Net ratepayer benefits, operational cost reductions, distribution capacity, reliability, and emissions reduction are primary objectives of DER orchestration and support the efficient and cost-effective integration of DERs into the electric grid. Customer and aggregation participation pathways ~~may~~ will support achievement of these objectives, provided the DER orchestration framework is properly designed. This includes appropriate locational and temporal planning, decision-grade data access, full value-stack evaluation, and transparent comparison of DER portfolios against traditional infrastructure alternatives."

2. Thermal overloads, customer energization and interconnection delays, system peak loading, and voltage deviations ~~are primary distribution-system constraints that DER orchestration may help address. DER orchestration may also provide operational benefits, including deferral of distribution-system investments~~ secondary-system constraints, local reliability needs, power quality issues, resilience needs, and distribution investment deferrals are distribution-system constraints, operational needs, or infrastructure-planning benefits that DER orchestration may help address. DER orchestration may also affect the need, timing, sizing, right-sizing, deferral, or avoidance of traditional distribution investments and provide transmission-related benefits where applicable through TSO-DSO coordination.

3. DER orchestration may provide multiple grid services including reliability, outage mitigation and avoidance, infrastructure deferral, and electrification support. The value and applicability of these services depend on the specific distribution system needs addressed.

4. ~~Adopting the 10 DER orchestration guiding principles listed in the March 23 Ruling, as modified by this decision, together with the addition of "safe and reliable grid operation," will help align the IOUs' Joint DER Orchestration Application with the overall goals of R.21-06-017~~ The DER orchestration framework should be guided by 11 guiding principles, including the 10 guiding principles proposed in the March 23 Ruling as modified by this decision and the additional principle of safe and reliable grid operation. Additional governance principles are necessary to ensure that an IOU-led DER orchestration framework provides nondiscriminatory market access, independent monitoring and oversight, optimization of existing distribution grid capacity before new capital investments, competitive neutrality, fair compensation for DER flexibility services, and timely access to accurate customer usage, DER, ICA, and grid data.

5. The existing Commission-led workshops and subsequent party comments ~~sufficiently developed the record to establish DER orchestration application requirements. Pre-application stakeholder engagement, including through a working group, will provide important input to inform the IOUs' Joint DER Orchestration Application."~~ developed the record sufficiently to establish minimum pre-application requirements and application contents, but additional stakeholder process, data access, and Commission oversight are necessary before the

Commission can determine whether any IOU DER orchestration proposal satisfies those requirements.

6. ~~Topics covered by the pre-application working group led by an IOU-contracted facilitator would include the following: (a) Guiding principles refinement;~~

~~(b) Valuation frameworks;~~
~~(c) Cost-effectiveness and benefit-cost methodologies;~~
~~(d) Interoperability, DSO visibility, and dispatch and control;~~
~~(e) Role of DER aggregators;~~
~~(f) Flexible dispatching mechanisms;~~
~~(g) IOU technical readiness;~~
~~(h) Ownership of technology;~~
~~(i) Phased implementation and deployment;~~
~~(j) DER orchestration and real-time pricing.~~

The pre-application working group should proceed in two phases. Phase 1 should address guiding principles, governance safeguards, data access, competitive neutrality, stakeholder participation, and minimum application requirements. Phase 2 should address valuation frameworks, cost-effectiveness and benefit-cost methodologies, interoperability, DSO visibility, dispatch and control, market participation, the role of DER aggregators, flexible dispatching mechanisms, IOU technical readiness, ownership of technology, phased implementation and deployment, TSO-DSO coordination, and DER orchestration and real-time pricing.

7. The value of DER flexibility is highly location dependent, and valuation frameworks for DER orchestration should reflect the specific use case and account for location and timing, where applicable, including location-specific benefits. System-level IEPR load modifiers alone are insufficient to capture the locational and temporal value of DER flexibility for circuit-, substation-, and secondary-system constraints.

8. The record does not support prescribing the ACC or any other single valuation tool for all DER orchestration use cases or portfolios. The ACC and LNBA may not fully capture the granular locational, temporal, resilience, transmission-related, equity, electrification-support, and distribution-system value relevant to DER orchestration.

10. DER aggregators ~~may~~ provide value by managing customer DERs and providing coordinated DER services, provided that their participation is subject to ~~the same performance and accountability requirements as IOUs~~ performance, measurement, verification, and accountability requirements appropriate to the services they provide and that do not create unnecessary barriers to competitive participation.

11. Distribution-level flexible dispatching mechanisms, when properly designed and implemented, ~~can~~ support DER orchestration by providing a structured means for enabling distribution-level services from DERs. Flexible dispatching mechanisms must be coordinated with DSO operational responsibilities to provide capacity capable of operating during a specific time window at a needed grid location.

12. Participant eligibility, value stacking, protections against double payment or double counting, performance and measurement and verification requirements, open and nondiscriminatory

participation, and appropriate governance and oversight are all relevant considerations for flexibility dispatch mechanisms.

17. A common DER orchestration framework approach ~~will provide efficiencies and better visibility of DER resources that will benefit customers~~ can provide efficiencies and better visibility of DER resources that benefit customers, provided the framework includes open and nondiscriminatory participation, competitive neutrality, decision-grade data access, transparent valuation and compensation, and Commission oversight sufficient to ensure that DER portfolios are fairly compared against traditional infrastructure alternatives.

19. Customer responses to dynamic pricing may affect load patterns, DER availability, timing, or other factors relevant to DER orchestration, and learnings from dynamic pricing may inform the development of DER orchestration where appropriate.

21. The EIS Part 2 final reports demonstrate substantial modeled potential for demand flexibility to reduce distribution infrastructure expenditures through 2040, including approximately $1.8 billion for PG&E, $320 million to $1.38 billion for SCE, and $697 million for SDG&E, depending on the utility and scenario. Although these results do not establish project-specific savings without further validation, they demonstrate the potential for demand flexibility to materially reduce projected distribution infrastructure requirements.

22 Electrification load, DER deployment, distribution constraints, and infrastructure investments should be evaluated together in the locations and hours where they interact.

23. ~~21. Demand Flexibility Scenario assumptions in EIS Part 2 need additional validation before being fully integrated into distribution planning. However, t~~The potential value of the Demand Flexibility Scenarios warrant development of a phased process for incorporating demand flexibility into the DPEP.

24. ~~22. IOUs developed methodologies are necessary for incorporating demand flexibility into DPEP at the circuit and substation level.~~ Transparent, stakeholder-reviewed methodologies are necessary for incorporating demand flexibility into DPEP at the circuit, substation, and secondary-system level, using utility operational data where necessary and subject to Commission oversight.

25. ~~23. Significant uncertainty exists about customer participation in distributed energy storage programs and their dispatchability~~ While additional validation may be needed for specific distributed storage participation and dispatch assumptions in DPEP, distributed storage is a controllable DER capable of providing demand flexibility, infrastructure deferral, resilience, and other grid services when paired with appropriate tariffs, contracts, telemetry, dispatch, and performance requirements.

26. Existing demand-side grid support, virtual power plant, distributed storage, managed-charging, demand-response, and local-flexibility activities demonstrate that DER portfolios are not merely theoretical resources and can provide measurable grid services when supported by appropriate telemetry, dispatch, compensation, settlement, and performance requirements. These

existing activities should inform DER orchestration application requirements, pilot design, valuation, and criteria for broader deployment.

27. ~~24.~~ Resolution E-5144 found it "very important to integrate demand flexibility into scenario planning once the EIS Part 2 Study is completed"; because EIS Part 2 has now demonstrated material distribution cost-reduction potential from demand flexibility, the Commission should establish a phased process for incorporating demand flexibility into DPEP.

28. Guiding principles, governance safeguards, data access, and competitive-neutrality requirements are foundational issues that should be resolved before valuation, market design, dispatch, communications, interoperability, and implementation details are finalized. Sequencing the working group process in phases will allow the Commission, stakeholders, and IOUs to develop a coherent DER orchestration framework before the IOUs file their Joint DER Orchestration Application.

29. The March 23, 2026 Assigned Commissioner's Ruling specifically solicited comment on DSO incentive structures employed in other jurisdictions, including Great Britain and Australia. A comparative review of relevant governance, performance-accountability, and incentive mechanisms could inform the development of California's DER orchestration framework without requiring adoption of any particular external regulatory model.

Conclusions of Law

2. Net ratepayer benefits, operational cost reductions, reliability, and emissions reduction should be some of the primary objectives of DER orchestration.

3. The IOUs should demonstrate net ratepayer benefits at the use-case and portfolio levels based on measurable benefits and accounting for the full incremental costs necessary to implement and operate each use case or portfolio. Cost-effectiveness methodologies should recognize multiple distinct benefits provided by a DER orchestration use case or portfolio, while preventing double counting of the same benefit ~~level based on measurable benefits and accounting for the full incremental costs necessary to implement and operate each use case~~.

4. The IOUs should define and justify the grid services that DERs will provide, ~~such as reliability, outage mitigation or avoidance, infrastructure deferral, and electrification support, in their joint application for DER orchestration~~ including but not limited to reliability, outage mitigation or avoidance, infrastructure deferral, distribution capacity, voltage support, frequency regulation, local constraint relief, electrification support, flexible load management, resilience, and transmission-related benefits where applicable, in their joint application for DER orchestration.

5. DER orchestration cost-effectiveness and valuation methodologies should recognize that a single DER resource or portfolio may provide multiple distinct grid, customer, resilience, electrification, transmission-related, environmental, and/or operational benefits, and should allow those benefits to be counted where they are measurable, attributable, and not duplicative.

6. ~~5.~~ The IOUs should link each grid service provided by DERs to specific system and/or distribution needs and justify how those needs were identified. The IOUs should also identify where DER flexibility can provide dependable distribution capacity and ~~whether~~ how grid-utilization analysis ~~can~~ will be used to identify locations where DER orchestration can effectively address distribution-system needs.

7. ~~6.~~ Thermal overloads, customer energization and interconnection delays, system peak loading, and voltage deviations~~, and distribution investment deferrals should be considered in the joint IOU application as primary grid constraints or operational benefits that could be solved or enabled respectively through DER orchestration~~ secondary-system constraints, local reliability needs, power quality issues, resilience needs, and distribution investment deferrals should be considered in the Joint IOU Application as primary grid constraints, operational needs, or infrastructure-planning benefits that may be addressed through DER orchestration. The application should evaluate how DER orchestration can affect the need, timing, sizing, right-sizing, deferral, or avoidance of traditional distribution investments and provide transmission-related benefits where applicable through TSO-DSO coordination.

8. ~~7. The IOU DER orchestration framework application should be guided by the following 11 guiding principles:~~

~~• Net-Ratepayer benefits;~~
~~• Technology-neutral, performance-based;~~
~~• Locational and temporal value recognition;~~
~~• Efficient operation of the grid;~~
~~• Open access and Interoperability;~~
~~• Transparent participation pathways and compensation;~~
~~• Incremental, evidence-based implementation;~~
~~• Equity and customer protection;~~
~~• Cyber-secure and resilient;~~
~~• Preventing double compensation; and~~
~~• Safe and reliable grid operation.~~

The IOU DER orchestration framework application should be guided by enforceable principles that require the framework to: (a) maximize net ratepayer benefits; (b) remain technology-neutral and performance-based; (c) recognize locational and temporal value; (d) optimize operation and utilization of the existing distribution grid; (e) provide open, interoperable, and non-discriminatory access; (f) provide transparent participation pathways and fair compensation; (g) support incremental, evidence-based implementation; (h) protect equity and customers; (i) ensure cyber-secure, resilient, safe, and reliable grid operation; (j) prevent double compensation for the same benefit; (k) provide nondiscriminatory market access, operations, and dispatch; (l) provide independent monitoring and oversight of DSO and market functions; (m) optimize existing distribution grid capacity before authorization of capital investments; (n) preserve competitive neutrality of the DSO and any marketplace operator; and (o) provide timely access to accurate customer usage, DER, ICA, and grid data.

9. ~~8. The IOUs shall contract for a facilitator to jointly convene a working group meeting series. The topics covered should include the following:~~

~~a. Guiding principles refinement;~~
~~b. Valuation frameworks;~~
~~c. Cost effectiveness and benefit-cost methodologies;~~
~~d. Interoperability, DSO visibility, and dispatch and control;~~
~~e. Role of DER aggregators;~~
~~f. Flexible dispatching mechanisms;~~
~~g. IOU technical readiness;~~
~~h. Ownership of technology;~~
~~i. Phased implementation and deployment;~~
~~j. DER orchestration and real-time pricing.~~

The working group process should be supervised by Energy Division or conducted under Energy Division oversight and should proceed in two phases. Phase 1 should address guiding principles, governance safeguards, data access, competitive neutrality, stakeholder participation, and minimum application requirements. Phase 1 should produce an interim report filed and served in the application record before Phase 2 begins. Phase 2 should address valuation frameworks, cost-effectiveness and benefit-cost methodologies, flexible dispatching mechanisms, market participation, communications, interoperability, TSO-DSO coordination, IOU technical readiness, ownership of technology, phased implementation, and DER orchestration and real-time pricing.

10. ~~9.~~ The working group meeting series, including preparing a report to be included with the Joint IOU DER Orchestration Application, should be completed within ~~10~~ 12 months from the issuance of this decision. Energy Division ~~The IOUs~~ should allow parties to this proceeding to provide informal comments on the draft report within those ~~10~~ 12 months. The IOUs should then include the final report as part of the joint application to be filed within ~~12~~ 14 months of the issuance of this decision. The draft report, stakeholder comments, final report, and any non-consensus recommendations should be filed or served in the application record and included with the Joint IOU Application. The report must also identify areas of agreement and disagreement, along with stakeholder alternatives.

11. It is reasonable for the Commission, assigned Commissioner, or assigned Administrative Law Judge to establish minimum governance requirements after the Phase 1 interim report and before the Joint IOU DER Orchestration Application is filed, so that the application demonstrates compliance with Commission-adopted requirements for open and nondiscriminatory participation, competitive neutrality, Commission oversight, data access, market-participant roles, safeguards against utility self-preference, independent monitoring or dispute resolution, and comparison of DER portfolios against traditional infrastructure alternatives.

12. It is reasonable to require the Phase 1 working group to evaluate relevant DSO governance and regulatory incentive approaches from other jurisdictions, including Great Britain and Australia, to inform minimum governance requirements, competitive neutrality, independent oversight, performance accountability, and incentives for cost-effective DER alternatives to traditional infrastructure investments.

13. ~~11.~~ The IOUs should propose and justify in their joint DER orchestration application the valuation methodologies and metrics used to assess proposed DER orchestration use cases and

portfolios. The proposed methodologies should account for the specific use case or portfolio and, where applicable, its location and timing; differentiate between broader system-level, transmission-related, and location-specific distribution-system benefits; and identify measurable avoided or deferred infrastructure costs ~~and operational benefits~~ operational benefits, resilience benefits, and other non-duplicative stacked benefits.

14. ~~12.~~ The IOUs may propose the ACC, LNBA, or other valuation tools identified in the record but should explain why their selected tools and methodologies are appropriate for the DER orchestration use cases or portfolios being evaluated, including whether they provide the necessary level of locational, temporal, and value-stack granularity.

15. ~~13.~~ The Joint IOU Application should include a qualitative and, where feasible, quantitative discussion of equity, resilience, affordability, and local reliability benefits ~~discussion of equity benefits~~ that may result from proposed DER orchestration activities, ~~where appropriate~~ including benefits in disadvantaged and ESJ communities.

16. ~~14.~~ The IOUs should propose cost-effectiveness methodologies that ~~demonstrate a net benefit to ratepayers~~ properly value DER orchestration as a grid resource. Proposed methodologies should evaluate costs and benefits at the use-case and portfolio levels ~~level~~, account for location-specific and time-specific impacts ~~impacts~~ where applicable, and compare measurable benefits, including applicable avoided costs, against the full incremental costs necessary to implement and operate each use case or portfolio. The proposed methodologies shall include or justify the applicability of the Total Resource Cost test and, where appropriate, the Societal Cost Test, together with supplemental analyses necessary to assess material resilience, equity, emissions, transmission-related, local reliability, affordability, and electrification-support benefits not adequately captured by the selected tests. The IOUs should not rely solely on a narrow rate-impact screen in a manner that excludes DER portfolios that provide net system value or multiple distinct grid services.

17. DER orchestration frameworks should not limit DER resources or portfolios to a single grid service where they are technically capable of providing multiple distinct services. Valuation, cost-effectiveness, dispatch, settlement, and performance requirements should recognize stacked benefits while preventing double counting of the same benefit.

18. ~~15.~~ The IOUs should propose measurable performance, reliability, ~~and cost-effectiveness criteria for determining when a DER orchestration use case is ready to move from demonstration to broader deployment~~ data-access, customer-participation, and cost-effectiveness criteria for determining when a DER orchestration use case or portfolio is ready to move from demonstration to broader deployment. These criteria should be developed through the working group process, supported by transparent data and assumptions, and should account for stacked benefits, open participation, and the ability of DER portfolios to provide multiple distinct grid services.

19. ~~16.~~ The IOUs should identify the performance, ~~and reliability criteria DERs must satisfy before their capacity can be relied upon for distribution planning as well as how dependable DER capacity could be represented in distribution planning~~ reliability, availability,

dispatchability, measurement, verification, and data-access criteria that DER resources or portfolios must satisfy before their capacity can be relied upon for distribution planning, and should explain how dependable DER capacity will be represented in distribution planning. These criteria should be transparent, technology-neutral, proportionate to the grid service provided, and developed through the working group process.

20. ~~17.~~ The IOUs should explain how demonstrated DER capacity ~~could affect the need, timing, or sizing of traditional distribution investments~~ and DER portfolios will be evaluated before traditional infrastructure investments are authorized, sized, or accelerated, including how DER capacity could affect the need, timing, or sizing of traditional distribution investments.

21. ~~18. The IOUs should specify in their joint application (i) what information should be shared as part of the orchestration plan; (ii) with whom; (iii) with what required granularity/cadence/latency; and (iv) with what privacy/cybersecurity safeguards.~~ Decision-grade data access is necessary for DER orchestration, open participation, competitive neutrality, and verification of net ratepayer benefits. The working group report and Joint IOU Application should specify the historical and forecast grid-needs, load, constraint, ICA/hosting capacity, DER availability, and performance data that must be shared; with whom; at what granularity, cadence, and latency. Privacy and cybersecurity safeguards should accommodate secure, appropriately authorized data access, including through customer authorization and confidentiality or data-use agreements where applicable, rather than treating restrictions on public disclosure as a prohibition on otherwise permissible data sharing.

27. ~~24.~~ The IOUs should continue TSO-DSO coordination with CAISO during the application proceeding and incorporate relevant developments regarding DER visibility, data exchange, service prioritization, ~~and operational coordination into the application record~~ operational coordination, dual participation, and transmission-related benefits into the application record. The Joint IOU Application should explain how DER orchestration may reduce, defer, or better utilize transmission and distribution infrastructure where DER portfolios provide both local distribution services and bulk-system or transmission-related benefits.

28. ~~25.~~ IOUs should consider in their joint application the role of DER aggregators in an orchestration framework and allow aggregators to provide coordinated DER services where their participation adds value, is cost-effective, and does not introduce unnecessary complexity. Participating aggregators should be subject to t~~he same performance and accountability requirements as the IOUs~~ performance, measurement, verification, and accountability requirements appropriate to the grid services they provide, and those requirements should not create unnecessary barriers to competitive participation.

29. ~~26.~~ The IOUs should propose and justify in the joint application flexible dispatching mechanisms that enable DERs to provide distribution-level grid services based on identified system needs. The proposed mechanisms should ~~address participant eligibility, protections against double payment or double counting, and performance, measurement, and verification requirements~~ allow DER resources and portfolios to provide multiple distinct grid services where technically capable, including distribution capacity, local constraint relief, voltage support,

reliability, outage mitigation or avoidance, infrastructure deferral, electrification support, resilience, and transmission-related benefits where applicable. The proposed mechanisms should address participant eligibility, settlement, compensation, protections against double payment or double counting of the same benefit, and performance, measurement, and verification requirements.

30. ~~27.~~ The IOUs should describe the operational coordination necessary to enable communication with and dispatchable control over participating DERs to respond to DSO operational needs, identifying implementation differences across the IOUs where necessary. Proposed communication, telemetry, and control requirements should be open, interoperable, technology-neutral, and no more burdensome than necessary to verify performance and maintain safety and reliability, so that current, least-cost, and least-regrets technologies can participate where they are capable of providing the relevant grid service.

31. ~~28.~~ The IOUs should identify in their joint application the roles of utilities, aggregators, CCAs, customers, and other DER providers and address safeguards for competitive neutrality and appropriate Commission oversight. These safeguards should apply to need identification, data access, eligibility rules, dispatch priority, compensation, settlement, performance evaluation, and decisions to procure DER services or pursue traditional infrastructure alternatives.

33. ~~30.~~ The IOUs should include in their Joint DER Orchestration Application the specific criteria by which they will demonstrate their individual technological and operational readiness to deploy DER orchestration at scale in a manner that incorporates consistent foundational components that are working toward a common DER orchestration framework. IOU readiness should include the ability to support open and nondiscriminatory participation, decision-grade data sharing, interoperable communications, aggregator and CCA participation, transparent settlement, and Commission oversight.

37. ~~34.~~ The IOUs' joint DER orchestration application must ~~specify the source of funding or whether proposed technology investments will be customer- or utility-owned~~ identify the funding sources, ownership arrangements, and operational responsibilities associated with proposed technology investments and DER orchestration services. The application should evaluate utility-owned and utility-operated solutions alongside customer-, CCA-, aggregator-, and independently provided alternatives using transparent, consistent criteria for lifecycle costs, reliability, interoperability, performance, scalability, and accountability. The evaluation should address potential conflicts of interest arising from utility incentives to pursue rate-based capital investments and demonstrate that utility ownership or operational control does not result in preferential treatment or the exclusion of cost-effective nonutility solutions.

39. ~~36.~~ While the EIS Part 2 Equity Scenario findings should not be ~~integrated into the DPEP process~~ treated as determinative project-specific inputs without appropriate validation, they should inform identification of candidate locations for DER investment in disadvantaged and environmental and social justice communities ~~the IOUs must identify candidate locations for DER investment in disadvantaged and ESJ communities and require project tracking for projects~~

~~in disadvantaged and ESJ communities~~. The IOUs should incorporate these locations into DPEP, GNA, and DDOR planning as planning-grade screens for evaluating DER portfolios that may reduce or defer infrastructure upgrades, improve resilience, support electrification, or provide local reliability benefits. Project tracking should identify the DER alternatives evaluated, resulting planning or procurement decisions, reasons for rejecting feasible alternatives, and progress toward realizing measurable infrastructure savings and community benefits.

40. ~~37.~~ The IOUs should propose a Load Flexibility Scenario as the fourth scenario in the annual DPEP Scenario Planning process. The scenario should support identification of candidate locations where demand flexibility and DER portfolios may cost-effectively reduce, defer, avoid, or right-size traditional distribution infrastructure investments. Its outputs should inform distribution needs assessments and evaluation of infrastructure alternatives early enough to influence infrastructure investment decisions, subject to appropriate validation of project-specific assumptions and performance requirements.

44. ~~41.~~ The IOUs should use the methodological lessons and directional findings from EIS Part 2 as the analytical foundation for a Load Flexibility Scenario proposal, including identification of candidate locations, data sources, assumptions, validation steps, and the process for translating scenario outputs into GNA, DDOR, and DPEP planning decisions, and follow the same staged pathway the Commission used to establish the scenario planning framework itself: a joint IOU advice letter defining both the technical basis for Load Flexibility Scenario inputs and implementation in the subsequent DPEP cycle.

45. Because EIS Part 2 demonstrates material distribution-cost reduction potential from demand flexibility and DER portfolios, the Joint IOU DER Orchestration Application should include a savings-realization plan identifying how the IOUs will identify, pursue, measure, and report distribution infrastructure cost reductions, operational cost reductions, and other net ratepayer benefits made possible by DER orchestration and Load Flexibility Scenario implementation.

46. ~~42.~~ It is reasonable to affirm all Track 1 and Track 2 rulings made by the assigned ALJ or the assigned Commissioner related to the issues considered in this decision.

47. ~~43.~~ It is reasonable to deny all motions related to Track 1 and Track 2 of this proceeding ~~that were not ruled on~~ only to the extent they seek relief inconsistent with this decision, while preserving the data-access, governance, open-access, competitive-neutrality, and stakeholder-participation issues raised in those motions for resolution in the working group, Load Flexibility Scenario process, and Joint IOU Application proceeding.

Ordering Paragraphs

1. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall submit a Joint Distributed Energy Resources Orchestration Application to the Commission within ~~12~~ 14 months of the issuance of this decision.

2. ~~Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall host a working group meeting series to address the topic areas this decision directs the utilities to include in a Joint Distributed Energy Resources Orchestration Application. This includes the following:~~

~~a. Guiding principles refinement;~~
~~b. Valuation frameworks;~~
~~c. Cost effectiveness and benefit-cost methodologies;~~
~~d. Interoperability, DSO visibility, and dispatch and control;~~
~~e. Role of DER aggregators;~~
~~f. Flexible dispatching mechanisms;~~
~~g. IOU technical readiness;~~
~~h. Ownership of technology;~~
~~i. Phased implementation and deployment;~~
~~j. DER orchestration and real-time pricing.~~

Energy Division shall supervise a two-phase working group meeting series. Energy Division may retain a facilitator or direct the IOUs to retain a facilitator subject to Energy Division oversight and guidance. Phase 1 shall address guiding principles, governance safeguards, data access, competitive neutrality, stakeholder participation, and minimum application requirements. The Phase 1 interim report shall be filed by the IOUs and served no later than 120 days after issuance of this decision. The Phase 1 interim report shall identify areas of agreement, disagreement, stakeholder alternatives, and proposed minimum application requirements. Phase 2 shall address valuation, cost-effectiveness, flexible dispatch, communications, interoperability, TSO-DSO coordination, market participation, implementation, and related technical issues.

3. The Phase 1 working group shall evaluate DSO governance and utility regulatory incentive structures that may affect the selection of DER alternatives, including existing cost-recovery incentives, shared-savings mechanisms, performance-based incentives, and relevant approaches used in other jurisdictions, including Great Britain's Ofgem and the Australian Energy Regulator. The review shall assess whether these mechanisms could reduce structural preferences for traditional capital investments, promote independent oversight and competitive neutrality, strengthen performance accountability, and produce verifiable net ratepayer benefits. The Phase 1 interim report required by Ordering Paragraph 2 shall identify relevant findings, their applicability and limitations in California, and areas of stakeholder agreement and disagreement, including alternative recommendations. The Commission shall consider these findings when establishing minimum governance requirements pursuant to Ordering Paragraph 4, before the Joint IOU Application is filed.

4. The Commission shall establish minimum governance requirements for the Joint DER Orchestration Application following consideration of the Phase 1 interim report, including its review of relevant governance and regulatory incentive approaches, and the existing proceeding record. Within 60 days after submission of the Phase 1 interim report, the assigned Commissioner or assigned Administrative Law Judge shall issue a ruling, proposed decision, or other appropriate procedural determination identifying the governance requirements that must be addressed in the Joint IOU DER Orchestration Application. Those requirements shall address open and nondiscriminatory participation, competitive neutrality, Commission oversight, data

access, market-participant roles, safeguards against utility self-preference, independent monitoring or dispute resolution, and criteria for comparing DER portfolios against traditional infrastructure alternatives. The Joint IOU DER Orchestration Application shall demonstrate compliance with those requirements.

5. ~~3. The working group and draft working group report shall be submitted to parties of this proceeding for informal comment within 10 months of the issuance of this decision. The final working group report, which will consider the comments on the informal report, shall be included as an attachment to the Joint Investor-Owned Utilities Distributed Energy Resources Orchestration Application.~~ The Investor-Owned Utilities shall circulate a draft Phase 2 working group report to parties in this proceeding for informal comment sufficiently in advance of the final report's completion. The final Phase 2 working group report shall identify areas of agreement and disagreement, stakeholder alternatives, and any non-consensus recommendations. The Phase 1 interim report, draft and final Phase 2 working group reports, and stakeholder comments shall be filed and served in this proceeding and included with the Joint IOU DER Orchestration Application.

6. ~~4.~~ The working group meeting series and ~~joint application shall address and include the primary objectives of distributed energy resources orchestration as set forth in this decision~~ Joint IOU DER Orchestration Application shall address and include the primary objectives of DER orchestration, including maximizing net ratepayer benefits, reducing operational costs, increasing distribution capacity, improving reliability and resilience, reducing emissions, enabling open customer and aggregator participation, supporting electrification, and ensuring transparent comparison of DER portfolios against traditional infrastructure alternatives.

7. ~~5.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to define and justify in their Joint Distributed Energy Resources (DER) Orchestration Application the proposed grid services that DERs will provide, including but not limited to reliability, outage mitigation or avoidance, infrastructure deferral, distribution capacity, power quality, voltage support, frequency regulation, local constraint relief, electrification support, flexible load management, resilience, and transmission-related benefits where applicable. ~~such as reliability, distribution capacity, outage mitigation or avoidance, infrastructure deferral, and electrification support~~.

8. ~~6.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company~~, collectively the Investor-Owned Utilities (IOUs),~~ are ordered to link each grid service proposed in their Joint Distributed Energy Resources (DER) Orchestration Application to specific system or distribution needs and explain how these needs were identified. The IOUs shall identify where ~~The IOUs are ordered to identify where~~ DER flexibility can provide dependable distribution capacity and ~~whether~~ how grid-utilization analysis ~~can~~ will be used to identify locations where DER orchestration can effectively address distribution-system needs. The Joint IOU Application shall evaluate grid services at the use-case and portfolio levels and shall recognize that a single DER resource or portfolio may provide multiple distinct grid, customer, resilience, electrification, transmission-related, environmental, and operational benefits where those benefits are measurable, attributable, and not duplicative.

9. ~~7.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to consider thermal overloads, customer energization and interconnection delays, system peak loading, and voltage deviations, secondary-system constraints, local reliability needs, power quality issues, resilience needs, and distribution investment deferrals are distribution-system constraints, operational needs, or infrastructure-planning benefits that may be addressed through DER orchestration in the Joint DER Orchestration Application. The Joint IOU DER Orchestration Application shall evaluate how DER orchestration can affect the need, timing, sizing, right-sizing, deferral, or avoidance of traditional distribution investments and provide transmission-related benefits, including reduced congestion, improved utilization, or avoided or deerred transmission investment where applicable through TSO-DSO coordination. ~~as primary grid constraints that may be addressed through distributed energy resources orchestration in their formal application~~.

10. ~~8.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to follow the following enforceable principles in the development, review, and implementation of their formal application: (a) maximize net ratepayer benefits; (b) remain technology-neutral and performance-based; (c) recognize locational and temporal value; (d) optimize operation and utilization of the existing distribution grid; (e) provide open, interoperable, and non-discriminatory access; (f) provide transparent participation pathways and fair compensation; (g) support incremental, evidence-based implementation; (h) protect equity and customers; (i) ensure cyber-secure, resilient, safe, and reliable grid operation; (j) prevent double compensation for the same benefit; (k) provide nondiscriminatory market access, operations, and dispatch; (l) provide independent monitoring and oversight of DSO and market functions; (m) optimize existing distribution grid capacity before authorization of capital investments; (n) preserve competitive neutrality of the DSO and any marketplace operator; and (o) provide timely access to accurate customer usage, DER, ICA, and grid data.

11. ~~9.~~ As part of the working group meeting series, or in addition, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, collectively the Investor-Owned Utilities (IOUs) shall jointly convene at least one pre-application stakeholder workshop ~~during the period between issuance of the draft working group report and the application filing deadline~~ after the Phase 1 interim report and at least one stakeholder workshop after issuance of the draft final working group report. The workshops shall be conducted under Energy Division oversight and shall provide parties an opportunity to address areas of agreement, disagreement, stakeholder alternatives, and minimum application requirements. Additional joint or utility-specific public engagement may occur in consultation with Energy Division and shall occur sufficiently early to inform application development without delaying the application filing deadline established by this decision. ~~In consultation with Energy Division, the IOUs may conduct additional joint or utility-specific public engagement as needed. Such engagement shall occur sufficiently early to inform application development without delaying the application filing deadline established by this decision~~.

12. ~~10.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to propose and justify in their Joint Distributed Energy

Resources (DER) Orchestration Application valuation methodologies to assess the value of each DER orchestration use case and portfolio. The proposed methodologies shall account for the specific use case or portfolio and, where applicable, its location, timing, duration, performance obligation, and beneficiaries. The methodologies shall distinguish among system-level, transmission-related, distribution-system, circuit-level, and secondary-system benefits, and shall identify measurable avoided or deferred infrastructure costs, operational benefits, resilience benefits, and other non-duplicative stacked benefits. Where a single DER resource or portfolio provides multiple distinct grid, customer, resilience, electrification, transmission-related, environmental, or operational benefits, those benefits shall be counted where they are measurable, attributable, and not duplicative. ~~The proposed methodologies shall account for the specific use case and its location and timing, where applicable. The proposed methodologies should also distinguish between locational benefits at the system level and circuit level.~~

13. ~~11.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to propose valuation and performance metrics to evaluate the effectiveness of distribution energy resources (DER) orchestration in their Joint DER Orchestration Application, including metrics for net ratepayer benefits, avoided or deferred infrastructure costs, improved grid utilization, energization and interconnection support, DER participation, performance of procured grid services, resilience, equity, emissions reductions, and transmission-related benefits where applicable.

14. ~~12.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company may use the Avoided Cost Calculator, Locational Net Benefits Analysis, or other valuation tools in their proposed valuation methodologies but they must explain why the selected tools and methodologies are appropriate for the respective distributed energy resources orchestration use case and/or portfolio, including whether the tools provide the necessary locational, temporal, and value-stack granularity. Where a selected tool does not fully capture distribution-system, transmission-related, resilience, equity, electrification-support, environmental, or operational benefits, the IOUs shall propose supplemental methods to capture those benefits where they are measurable, attributable, and not duplicative.

15. ~~13.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall should continue Transmission System Operator-Distribution System Operator coordination with the California Independent System Operator during the Joint Distributed Energy Resources (DER) Orchestration Application proceeding and incorporate relevant developments regarding DER visibility, data exchange, service prioritization, dual participation, ~~and~~ operational coordination, and transmission-related benefits into the application record. The Joint IOU Application shall explain how DER orchestration can maximize net ratepayer value by coordinating local distribution services with bulk-system needs, including reduced congestion, improved utilization of existing transmission and distribution infrastructure, and avoided or deferred transmission investment where applicable.

16. ~~14.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to include a qualitative ~~discussion of equity benefits in their distributed energy resources orchestration use case valuations where appropriate~~ and, where

feasible, quantitative discussion of equity, resilience, affordability, and local reliability benefits in their DER orchestration use case and portfolio valuations, including benefits in disadvantaged and environmental and social justice communities.

17. ~~15.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to propose valuation and cost-effectiveness methodologies that assess the capabilities, measurable benefits, full incremental costs, and dependable performance of both individual DER resources and coordinated DER portfolios within each relevant use case. ~~propose cost-effectiveness methodologies for each use case in their Joint Distributed Energy Resources (DER) Orchestration Application that demonstrate net benefit to ratepayers by comparing measurable benefits against the full incremental costs necessary to implement and operate each DER orchestration use case, accounting for location-specific impacts.~~ The methodologies shall demonstrate net benefits by comparing measurable benefits against the full incremental costs necessary to implement and operate individual DER or a portfolio within each use case, accounting for location-specific and time-specific impacts where applicable. The proposed methodologies shall include or justify the applicability of the Total Resource Cost test and shall include a supplemental societal and non-energy benefits analysis for each use case or portfolio that may provide resilience, equity, emissions, transmission-related, local reliability, affordability, or electrification-support benefits. Where such benefits are material but not monetized, the IOUs shall quantify them where feasible, provide a qualitative assessment where quantification is not feasible, and explain how the Commission should consider those benefits in determining whether the use case or portfolio provides net system value. The IOUs shall not rely solely on a narrow rate-impact screen in a manner that excludes DER portfolios that provide net system value.

18. ~~16.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to propose measurable performance, reliability, data-access, customer-participation, and cost-effectiveness criteria in their Joint Distribution Energy Resources (DER) Orchestration Application for determining when a DER orchestration use case or portfolio is ready to move from demonstration to broader deployment. These criteria shall be developed through the working group process, supported by transparent data and assumptions, and account for stacked benefits, open participation, and the ability of DER portfolios to provide multiple distinct grid services.

19. ~~17.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to propose in their Joint Distributed Energy Resources (DER) Orchestration Application the performance, reliability, availability, dispatchability, measurement, verification, and data-access criteria that ~~and reliability criteria~~ DER~~s~~ resources or portfolios must satisfy before their capacity can be relied upon for distribution planning ~~as well as how dependable DER capacity could be represented in distribution planning~~. The IOUs shall explain how dependable DER capacity will be represented in distribution planning. These criteria shall be transparent, technology-neutral, proportionate to the grid service provided, and developed through the working group process. Where DER capacity relied upon for distribution planning may also provide transmission-related benefits, the IOUs shall identify the performance

and availability conditions necessary to support those benefits and explain how they will be valued without double counting.

20. ~~18.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to explain in their Joint Distributed Energy Resources (DER) Orchestration Application how ~~demonstrated DER capacity could affect the need, timing, or sizing of traditional distribution investments~~DER resources and portfolios will be evaluated before traditional infrastructure investments are authorized, sized, or accelerated. The Joint IOU Application shall explain how demonstrated or reasonably procurable DER capacity could affect the need, timing, sizing, right-sizing, deferral, or avoidance of traditional distribution investments. The explanation shall address how DER orchestration can allow distribution upgrades to be sized based on updated forecasts, actual load growth, and the grid needs of the future, rather than solely on the near-term need or customer request that initially triggers an upgrade. The application shall also explain how DER portfolios will be compared against traditional infrastructure alternatives using equivalent assumptions regarding location, timing, planning horizon, reliability, availability, performance, risk, and total costs and benefits.

21. ~~19.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to specify in their Joint Distributed Energy Resources Orchestration Application the historical and forecast grid-needs, load, constraint, ICA/hosting capacity, DER availability, customer-authorized usage, enrollment, dispatch, settlement, and performance data that must be shared; with whom; at what granularity, cadence, and latency; through what interfaces; and subject to what privacy and cybersecurity safeguards ~~(i) what information should be shared as part of the orchestration plan; (ii) with whom; (iii) with what required granularity/cadence/latency; and (iv) with what privacy/cybersecurity safeguards~~. The application shall propose data-sharing requirements sufficient to ensure that lack of actionable data does not prevent or prejudice participation by CCAs, DER aggregators, customers, or other DER providers, and shall identify data-quality standards, correction timelines, and interim solutions where required data systems are not yet fully available.

22. ~~20.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered propose in their Joint Distributed Energy Resources Orchestration Application open, standardized, and interoperable communication protocols that reduce reliance on proprietary original equipment manufacturer clouds, ~~and~~ enable grid-edge innovation, and support communication among utility grid-level systems, CCA-operated DERMS, aggregator platforms, third-party edge DERMS, and customer-managed DERs. Any proposed deviation shall include justification for why open, standardized, and interoperable communication protocols will not meet the proposed needs.

23. ~~21.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered address in their Joint Distributed Energy Resources (DER) Orchestration Application communication barriers ~~such as excessive access fees, limited functionality, and vendor lock-in that can undermine DER program cost-effectiveness and ratepayer value~~ such as access fees that exceed reasonable incremental costs, limited

functionality, unreasonable certification or integration requirements, and vendor lock-in that can undermine DER program cost-effectiveness, competitive participation, and ratepayer value.

24. ~~22.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to identify in their Joint Distributed Energy Resources (DER) Orchestration Application each utility's existing systems, pilots, Grid Modernization Plan capabilities, GRC-authorized investments, and other ~~and~~ capabilities that can support DER orchestration~~,~~; additional capabilities needed to implement their proposals~~,~~; and how each utility's proposed architecture reflects ~~their~~ its technical and operational readiness to move forward with a consistent DER orchestration framework.

25. ~~23.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to distinguish between ~~existing and previously authorized capabilities from proposed new investments~~ previously authorized, and pending capabilities and proposed new investments, and explain why any proposed incremental investment is necessary, not duplicative of existing or authorized funding, and directly tied to DER orchestration requirements in their Joint Distributed Energy Resources Orchestration Application.

26. ~~24.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to continue transmission system operator-distribution system operator coordination with the California Independent System Operator during the Distributed Energy Resources (DER) Orchestration Application proceeding and incorporate relevant developments regarding DER visibility, data exchange, service prioritization, ~~and~~ operational coordination, dual participation, and transmission-related benefits into the application record. The application shall explain how local DER orchestration can be coordinated with CAISO requirements so that DER portfolios can provide local distribution services while also supporting bulk-system reliability, improved transmission utilization, reduced congestion, and avoided or deferred transmission investment where applicable.

27. ~~25.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to address in their Joint Distributed Energy Resources (DER) Orchestration Application the potential role of DER aggregators, CCAs, customers, and other DER providers in their proposed orchestration frameworks. ~~If aggregators are included they must add value, not undermine the goal of cost effectiveness, nor add unnecessary complexity.~~ The application shall allow qualified aggregators, CCAs, customers, and other DER providers to provide coordinated DER services where their participation adds value and is cost-effective. Participation requirements shall be based on the grid service provided and shall not create unnecessary barriers to competitive participation.

28. ~~26.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to propose in their Joint Distributed Energy Resources (DER) Orchestration Application ~~a~~ flexible dispatching mechanisms that enables DER~~s~~ resources and portfolios to ~~offer grid services and addresses participant eligibility, settlement structures, protections against double payment or double counting, and performance, measurement and verification requirements~~ provide distribution-level grid services based on

identified system needs. The proposed mechanisms shall allow DER resources and portfolios to provide multiple distinct grid services where technically capable, including distribution capacity, local constraint relief, voltage support, reliability, outage mitigation or avoidance, infrastructure deferral, electrification support, resilience, and transmission-related benefits where applicable. The application shall address how virtual power plants, DER aggregations, distributed storage, managed EV charging, flexible load, flexible interconnection, and other DER portfolios can provide these services individually or in combination. The proposed mechanisms shall address participant eligibility, settlement, compensation, protections against double payment or double counting of the same benefit, and performance, measurement, and verification requirements.

29. ~~27.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to explain in their Joint Distributed Energy Resources (DER) Orchestration Application how ~~their~~ proposed flexible dispatching mechanisms can schedule and dispatch DER flexibility based on identified distribution system needs and ~~how they will exercise communication and dispatch control over participating DERs, including the mechanisms necessary to ensure DERs respond to distribution system operator operational needs~~ how participating DERs will respond to DSO operational needs. Proposed communication, telemetry, and control requirements shall be open, interoperable, technology-neutral, and no more burdensome than necessary to verify performance and maintain safety and reliability. The application shall explain how current, least-cost, and least-regrets technologies, including CCA-operated DERMS, aggregator platforms, third-party edge DERMS, and customer-managed DERs, can participate where capable of providing the relevant grid service.

30. ~~28.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to explain in their Joint Distributed Energy Resources (DER) Orchestration Application how their proposed flexibility dispatch mechanisms enable open and non-discriminatory participation for utility-managed, ~~community choice aggregator~~CCA-managed, aggregator-managed, ~~energy services aggregator , and~~ customer-managed, community-managed, and third-party-managed DERs.

31. ~~29.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to identify in their Joint Distributed Energy Resources (DER) Orchestration Application the roles of utilities, DER aggregators ~~energy service aggregators~~, community choice aggregators, customers, local governments, Tribal governments, and other DER providers and address safeguards for competitive neutrality and appropriate Commission oversight. These safeguards shall apply to need identification, data access, eligibility rules, dispatch priority, compensation, settlement, performance evaluation, and decisions to procure DER services or pursue traditional infrastructure alternatives.

32. ~~30.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to demonstrate in their Joint Distributed Energy Resources (DER) Orchestration Application their level of readiness for DER orchestration, and that readiness should be assessed based on proven capabilities including tested pilots and results, or based on capabilities recently acquired, soon to be acquired, and that are reasonably expected to be ready to support DER orchestration in the time frame of the application implementation

process. IOU readiness shall also include the ability to support open and nondiscriminatory participation, decision-grade data sharing, interoperable communications, aggregator and CCA participation, transparent settlement, and Commission oversight.

37. ~~35.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to consider dynamic pricing in their Joint Distributed Energy Resources (DER) Orchestration Application where relevant to the development of DER orchestration, including where customer responses to dynamic pricing may affect load patterns, DER availability, timing, or the cost-effectiveness of proposed DER orchestration use cases. Dynamic pricing shall be treated as complementary to, and not a substitute for, procurement, dispatch, compensation, and settlement mechanisms that allow DER portfolios to provide measurable grid services.

38. ~~36.~~ Within 90 calendar days of the issuance if this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to present their proposal of for incorporating a Load Flexibility Scenario into the Scenario Planning process of the Distribution Planning and Execution Process (DPEP) at a full-day stakeholder workshop with presentations addressing the technical elements outlined below.

- Technical methodologies and foundational assumptions of a Load Flexibility Scenario;
- How the Load Flexibility Scenario relates to and interacts with existing Low, Base, and High scenarios (e.g., whether it is independent from the other scenarios or if it modifies them);
- Integration with each utility's decision logic framework and any required modifications to existing decision logic;
- Proposed criteria for determining implementation readiness;

The workshop shall also address identification of candidate locations, data sources, assumptions, validation steps, and the process for translating Load Flexibility Scenario outputs into GNA, DDOR, and DPEP planning decisions.

39. ~~37.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, collectively the Investor-Owned Utilities (IOUs), are ordered to file a joint Tier 3 advice letter within 60 calendar days after the workshop providing the technical basis for Load Flexibility Scenario inputs. At minimum, the advice letters shall include:

- Each IOU's load-modifier (load flexibility) methodology, including whether inputs are derived from CEC's D-Flex Tool (2023) technical potential outputs, utility-developed disaggregated outputs, a hybrid of the two inputs, or another utility method;
- Locational granularity at which each IOU can resolve demand flexibility inputs (substation, circuit) and the disaggregation method;
- Temporal granularity of modeled flexibility (hourly profiles, peak coincidence with local constraints);
- The process for using the Load Flexibility Scenario to identify candidate circuits, substations, secondary-system constraints, disadvantaged and ESJ communities, and other priority locations where demand flexibility and DER portfolios may reduce or defer distribution upgrades, improve resilience, support electrification, provide transmission-related benefits, or provide local reliability benefits. The advice letter shall explain how

the scenario will account for value stacking where DER portfolios provide multiple distinct, measurable, and non-duplicative benefits;

- Applicability and thresholds: the criteria and locations where each IOU proposes to apply the Load Flexibility Scenario, including how each IOU will determine whether ~~the determination that~~ system-level levers ~~(e.g., traditional upgrades~~, IEPR-forecasted load growth assumptions, pending load categories,~~)~~ traditional upgrades, DER portfolios, or combinations of these measures are sufficient to address distribution grid constraints;
- Proposed definition of the scenario's role, prioritization (similar to the Low Scenario) versus sizing/timing (similar to the High Scenario);
- Guardrails, including reconciliation with the IEPR forecast and prevention of counting multiple times against existing scenarios, pending loads and other demand side management programs;
- Data infrastructure dependencies (including AMI 2.0 timing) and any temporary solutions pending full deployment of such dependencies; and
- Description of how scenario outputs would be reported in Grid Needs Assessment/Distribution Upgrade Project Report filings.
- How the Load Flexibility Scenario will be incorporated into the existing DPEP Scenario Planning Framework starting in the 2027-2028 DPEP cycle.

40. ~~38.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to use the methodological lessons and directional findings from Electrification Impact Study Part 2 as the analytical foundation for a Load Flexibility Scenario and as a planning-grade screen to identify candidate circuits, substations, secondary-system constraints, and priority communities where DER portfolios, managed charging, storage, flexible interconnection, dynamic pricing, and DERMS-enabled dispatch should be evaluated before traditional infrastructure upgrades are authorized. Electrification load, DER deployment, distribution constraints, and infrastructure investments should be evaluated together in the locations and hours where they interact.

41. ~~39.~~ Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, collectively the Investor-Owned Utilities (IOUs), are ordered to identify candidate locations for distributed energy resource investment in disadvantaged and environmental and social justice (ESJ) communities based on the findings of the Electrification Impact Study Part 2 Equity Scenario. Candidate locations shall be incorporated into DPEP, GNA, and DDOR planning as planning-grade screens where DER portfolios may reduce or defer distribution upgrades, improve resilience, support electrification, and provide local reliability benefits before traditional infrastructure solutions are authorized. The IOUs are additionally required to track project progress for all projects in disadvantaged and ESJ communities.

42. ~~40.~~ All rulings made by the assigned Administrative Law Judge or the assigned Commissioner related to Track 1 and Track 2 of this proceeding are affirmed."

43. ~~41.~~ All motions related to Track 1 and Track 2 of this proceeding that were not ruled on are denied, except the Center for Biological Diversity and Utility Consumers' Action Network Motion to Address Unaddressed Issues filed September 10, 2026, and Clean Coalition's Motion to Compel. These motions shall remain pending for separate disposition. Within 90 days of this

decision, the assigned Commissioner or Administrative Law Judge shall issue a ruling addressing the disposition of these motions or establishing the procedural process and schedule for resolving the outstanding issues they raise.

44. Within 90 days of this decision, the assigned Commissioner or assigned Administrative Law Judge shall issue a ruling identifying how Track 1 reports, party comments, and related record materials concerning DPEP data access, ICA/hosting capacity, grid-needs identification, and Load Flexibility Scenario implementation will be incorporated into the Phase 1 working group, Load Flexibility Scenario advice letter process, and Joint IOU DER Orchestration Application.

45. The Joint IOU DER Orchestration Application shall demonstrate how the proposed framework is consistent with and advances Public Utilities Code § 769 by evaluating locational benefits and costs of distributed resources, coordinating Commission-approved programs, incentives, and tariffs to maximize locational benefits and minimize incremental costs, identifying any incremental utility spending necessary to integrate cost-effective DER into distribution planning, and removing barriers to DER deployment in a manner that minimizes overall system costs and maximizes ratepayer benefits. The application shall also demonstrate how its grid-utilization assessments, identification of constrained distribution areas, and evaluation of DER alternatives will satisfy the applicable requirements of Public Utilities Code § 769.1.

46. The Joint IOU DER Orchestration Application shall include a savings-realization plan explaining how the IOUs will identify, pursue, measure, and report distribution infrastructure cost reductions, operational cost reductions, and other net ratepayer benefits made possible by DER orchestration and Load Flexibility Scenario implementation. The plan shall identify candidate locations, use cases, procurement pathways, performance metrics, reporting timelines, and barriers to realizing the distribution-cost reduction potential identified in EIS Part 2.

47. ~~42.~~ Rulemaking 21-06-017 remains open, and Track 2 shall remain open for the purpose of resolving outstanding governance, competitive-neutrality, and utility-incentive issues, including those raised in the September 10, 2026 Motion to Address Unaddressed Issues filed by the Center for Biological Diversity and Utility Consumers' Action Network. The Commission shall determine the appropriate safeguards and procedural disposition of those issues before deeming Track 2 complete. Referral to the pre-application working group or Joint IOU DER Orchestration Application alone shall not constitute their resolution.