BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) COMMENTS ON ASSIGNED COMMISSIONER'S PROPOSAL AND SECTION 2 AND SECTION 4 QUESTIONS REGARDING FLEXIBLE SERVICE CONNECTIONS

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Pursuant to the July 7, 2026 *Assigned Commissioner's and Administrative Law Judge's Ruling Requesting Comment on Assigned Commissioner's Proposal on Flexible Service Connections* ("Ruling") and the July 13, 2026 *Email Ruling Granting Schedule Modification*, Southern California Edison Company ("SCE") hereby submits its comments on the Assigned Commissioner's Proposal and its responses to the questions in Sections 2 and 4 of the Ruling.

Respectfully submitted,

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Attachment

Southern California Edison Company's Comments on Assigned Commissioner's Proposal and Section 2 and Section 4 Questions Regarding Flexible Service Connections

Introduction

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

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

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

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

It is clear that flexibility should play a larger role in the future grid. Utilities, aggregators, and technology providers should continue developing new approaches to support it. The question now is what are the technical capabilities, operational frameworks, customer

engagement methodologies, and policy structures necessary to cost effectively realize that potential at scale. To answer these questions, California must effectively transition from promising concepts and demonstrations to scalable implementation while preserving sufficient flexibility to quickly learn, refine, and optimize those approaches over time.

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

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

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

1. **Allow implementation and learning to proceed together.** Program deployment, framework development, and regulatory refinement should be done in parallel rather than sequentially, and be intentionally mutually reinforcing.
2. **Preserve flexibility in architecture and implementation.** Advanced capabilities such as AMI 2.0, Enterprise DERMS, Grid Edge DERMS, operating envelopes, and customer integration platforms will enable the foundational capabilities needed to support broader DER orchestration, but further insights are needed to provide the most robust framework.
3. **Recognize that long-term demand flexibility requires additional development.** Durable flexibility capable of use in planning for the purpose of capital deferral presents questions regarding customer participation, compensation, validation, and integration that warrant continued development and coordination across both tracks.

4. **Account for SCE's unique system topology.** SCE's electric system includes a distinct "middle layer" between the conventional radial distribution grid and the transmission system. This CPUC-jurisdictional networked subtransmission system introduces additional limitations and complexities that must be fully considered when developing Flexible Service Connection offerings and a broader DER Orchestration framework.

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

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

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

Ultimately, SCE believes the Commission is largely headed in the right direction. The proposals and questions presented in the twin Rulings identify many of the capabilities that will be necessary to support California's future grid. The challenge now is preserving sufficient flexibility within the policy framework to determine which approaches,

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

architectures, customer arrangements, and orchestration models ultimately deliver the greatest affordability, reliability, customer benefit, and grid value for Californians.

Responses to questions 1-9 of the Assigned Commissioner's and Administrative Law Judge's Ruling Requesting Comment on Assigned Commissioner's Proposal on Flexible Service Connections follow below.

1. **Please provide feedback on the Proposal itself, identifying any concerns with and/or support for the direction and background. Comments on the Proposal shall be provided within the same structure as the Proposal where possible (e.g., discussion of Operating Envelopes should come in Section 4 of party comments).**

SCE supports evaluating flexible alternatives where they can safely, reliably, and cost-effectively achieve customer and/or grid needs. In certain situations, flexible solutions will be an appropriate option alongside traditional infrastructure investments.

The Proposal would establish flexibility solutions as the default approach to dealing with constrained assets, in lieu of infrastructure upgrades. Such a requirement may not account for customer operational requirements, variability in feeder characteristics, technology readiness, planning uncertainty, operational complexity, and long-term reliability obligations. In providing limited power arrangements as the default mitigation for distribution transformer upgrades, time saved may be offset by the effort required to ensure customers are well-informed of the implications of not opting out.

IOUs should retain discretion to evaluate flexibility solutions and traditional upgrades based on safety, reliability, customer needs, economics, system conditions, and whether the customer has expressed interest in a flexible arrangement. Flexible solutions should be made available where appropriate, but they should not be imposed as a default mitigation step.

2. **Section 9 of the Proposal includes a summary of the recommendations for Commission action. Please provide feedback on the recommendations, being as specific as possible regarding the pros and cons of the proposed recommendations, and on the feasibility of implementation.**

Section 3. Distribution Capacity Determination

SCE's Overall Feedback and Recommendations on Section 3:

SCE supports continued improvement of load forecasting, hosting capacity methodologies, and distribution planning tools to better identify opportunities for flexibility. However, Section 3 should be refined to more accurately reflect how SCE currently

evaluates distribution capacity and plans its distribution system. The Proposal's discussion of planning and hosting capacity is largely focused on primary distribution facilities and does not fully account for the fact that SCE's CPUC-jurisdictional distribution system also includes subtransmission facilities, generally operating at 66 kV and 115 kV voltages, SCE's subtransmission system has a unique configuration in which each of its 45 subtransmission systems are radially supplied from the transmission system (typically through 220/115 kV or 220/66 kV A-bank transformers), while the underlying subtransmission lines are operated in a networked configuration. As a result, the subtransmission system is subject to planning, operational, and reliability requirements and considerations that are distinct from those applicable to primary distribution facilities. This distinction is important because the potential application of DER orchestration, load flexibility, and investment deferral opportunities must be evaluated in the context of both radial distribution and networked subtransmission systems to ensure reliability and operational risks are appropriately considered.

Additionally, the Proposal appears to conflate the Integration Capacity Analysis (ICA) with the Distribution Planning Process (DPP) and customer-specific engineering studies. ICA provides a snapshot of available grid hosting capacity. SCE's load ICA is intended to assist customers in making informed energization decisions, but load ICA does not serve the same function as the DPP or customer load studies. SCE's distribution planning and customer studies account for lateral circuit segments and incorporate load and DER forecasts at the structure level for both lateral and mainline facilities. Accordingly, the Proposal should avoid characterizing ICA limitations as evidence that the utility lacks planning visibility or analytical capability across primary distribution facilities. With that said, SCE is currently implementing significant improvements to its Load ICA as communicated in ongoing workshops and biannual reports in this proceeding – again for the benefit of customers, not the DPP.

The Proposal also overstates gaps in SCE's power flow modeling and overlooks important nuances regarding how distribution facilities are represented in existing planning tools. Several technical statements regarding mainline, lateral, and secondary distribution facilities should be corrected or clarified. SCE's distribution circuits are composed of mainline and branch line segments operated at primary distribution voltages, and SCE models primary conductors, including both mainline and branch line facilities, in power flow software. While SCE does not perform ICA on non-three-phase segments or nodes and does not model secondary service conductors in the same way, it is inaccurate to state broadly that lateral portions of the distribution system are not represented in detailed power flow models. The granularity and limitations of SCE's power flow modeling have been discussed at length in Track 1 of this proceeding as well as the closed Distribution

Resource Plan Proceeding, R. 14-08-013. The Proposal seems to miss many relevant details in this regard.

Similarly, the Proposal should clarify its discussion of forecasting. Grid capacity is not forecasted directly. Rather, load and DER forecasts are developed and then used as inputs into power flow modeling to simulate future system conditions and identify potential constraints. The Proposal's discussion should be revised to reflect this sequencing and avoid suggesting that power flow modeling itself is the forecasting mechanism.

SCE also recommends clarification regarding the Proposal's discussion of secondary-system topology and service transformers. SCE is not aware of a common configuration involving two stages of low-voltage step-down transformers after the distribution transformer to serve customer load. There may be limited circumstances where voltage is stepped down for meters or control equipment, but the Proposal's broader description may be more applicable to other utility systems and should not be generalized to SCE's distribution grid without further validation.

The Proposal may also overstate the precision currently available to determine dynamic customer-level capacity limits across all portions of the distribution system, particularly secondary systems where visibility and modeling capabilities remain less mature. Additional work should be performed to align planning methodologies, forecasting assumptions, AMI-enabled visibility, and DERMS capabilities before imposing broad operational requirements tied to capacity determinations.

Finally, SCE recommends that the Proposal distinguish between low-cost or no-cost mitigations, maintenance activities, and grid upgrades. Certain activities referenced in the Proposal may not be maintenance activities for general rate case classification purposes, and installing or relocating voltage regulation equipment could require changes to overhead or underground structures, placing such work closer to a grid upgrade than a low-cost mitigation.

SCE's Feedback on Section 3 Subsections:

Recommendation 3.1 does not pertain to SCE.

Recommendation 3.2 would provide limited incremental customer value while potentially requiring significant process, system, and administrative changes to implement. The recommendation directs the large IOUs to record the service conductor capacity and demand load values for each site as they are computed in the Engineering and Design energization step. This additional effort may have value in limited circumstances, such as where an existing customer seeks information before submitting an energization or load-increase request and could use that information to size a project within existing service

limitations. The recommendation is currently unclear regarding what information must be recorded, where it would be maintained, how and to whom it would be made available, and what costs would be incurred to establish and administer such a process.

Additionally, service conductor capacity is not the sole determining factor of whether an upgrade is required, as engineering evaluations also consider voltage drop, system protection, equipment configuration, and site-specific conditions. Furthermore, clarity is needed in regard to demand load values and the relevance of capturing that metric. The Commission should further clarify the intent and scope of this recommendation and focus any information-sharing requirements on circumstances where the information would provide actionable customer value.

Recommendation 3.3 would require the large IOUs to modify their Rule 2 Section H.7 to reflect that the PCS limit for controlled load is the lesser of connected load, demand load, or secondary conductor rating. Any modifications to Rule 2 should not create a default requirement for customers to install or operate under power control systems or other flexible connection arrangements. Any tariff changes must be carefully drafted so that controlled load provisions apply only where a customer elects to use such arrangements, and not to all customers as a general electrical service requirement.

SCE also notes that the recommendations to update Rule 2 to (1) incorporate IEEE 519 for Harmful Wave Form and Harmonics and to (2) correct the gendered references within the Rule were addressed in Advice 5848-E: Revision to Rule 2, Description of Service and Form CSD-393, Application and Contract for Electric Facilities: Permanent Service - Capacity in Excess Of 2,000 KVA, which was submitted July 7, 2026.

Recommendation 3.4 would require the IOUs, before initiating a ratepayer-funded distribution upgrade, to evaluate whether a Limited Power arrangement, Operating Envelope, or other flexible connection solution enabled by PCS can be used as a mitigation to safely satisfy the customer's requested capacity. While flexible connections can provide meaningful benefits in appropriate circumstances, requiring such evaluation across the full population of energization requests could add significant engineering effort, increase administrative costs, and potentially slow the very energization timelines that Track 3 and related proceedings seek to improve. Flexible service arrangements are not appropriate for every customer, capacity constraint, or upgrade need. A more workable approach would be to evaluate flexible connection options where the customer has indicated interest, where the option is technically feasible, and where it is likely to be more cost-effective than other available mitigations for participating and non-participating customers.

SCE recommends that the Commission establish a framework that preserves customer choice while allowing IOUs to develop appropriate eligibility criteria, evaluation processes, documentation requirements, and customer communication protocols through the proposed Tier 2 FSC Implementation Advice Letter. Such an approach would advance the Proposal's objectives while avoiding premature or overly broad implementation requirements that could create unnecessary costs, delay energization, or impose obligations on customers who do not seek or benefit from a flexible connection option.

Section 4. Operating Envelopes

SCE's Overall Feedback and Recommendations on Sections 4:

SCE supports continued exploration of operating envelopes as a tool to increase flexibility and improve utilization of grid infrastructure. SCE also supports further evaluation of static, variable, and dynamic approaches. However, the Proposal should better distinguish between operationally mature approaches and future capabilities that remain dependent on technology deployment, communications infrastructure, customer participation, and additional validation. For example, variable and dynamic operating envelopes rely on DERMS being fully operational.

Limited Power as Default Mitigation for Secondary Constraints

While UL 3141-certified technologies show promise, operational experience remains limited and implementation questions remain regarding customer acceptance, maintenance responsibilities, enforcement mechanisms, communications reliability, and long-term operational performance.

Limited-power solutions should remain one available tool rather than a mandatory default requirement. Customers may choose these arrangements where they receive a concrete benefit, such as faster energization, avoidance of customer-funded upgrade costs, or another financial or programmatic benefit. However, where customers are not responsible for the upgrade cost, the Proposal should not assume customers will voluntarily accept permanent limitations or accept incurring the incremental cost to design, install, and maintain power control equipment for an indefinite amount of time.

Static Operating Envelopes for Primary Constraints

SCE generally supports static operating envelopes because they align most closely with current FSC implementations and have the greatest operational maturity. Static operating envelopes provide an important bridge between current actionable controls and more advanced flexibility solutions. However, static approaches also have limitations,

particularly where multiple customers seek to share constrained capacity on the same limiting asset.

Variable Operating Envelopes for Primary and Secondary Constraints

Variable operating envelopes have the potential to increase capacity utilization and support greater customer flexibility where supporting systems and communications capabilities exist. Significant implementation challenges remain regarding forecasting accuracy, customer communication, and operational administration. The Proposal may underestimate these complexities.

Applying variable operating envelopes to secondary systems should at minimum be deferred pending further technical development and demonstration. SCE should not be required to implement variable operating envelopes across secondary systems before the necessary visibility, communications, forecasting, optimization, and operational processes are available and validated.

SCE also recommends clarifying that variable operating envelopes may require communication and technology capabilities comparable to dynamic operating envelopes. The Proposal's apparent distinction between the communications requirements for variable and dynamic operating envelopes may understate the technical capabilities needed to safely and reliably administer variable limits.

Dynamic Operating Envelopes for Primary Constraints

The Proposal's vision for dynamic operating envelopes relies on capabilities that are still under development and not yet broadly deployed. SCE's ongoing DERMS and AMI 2.0 efforts are advancing necessary foundational capabilities, but these systems are not yet operating at the scale contemplated by the Proposal. Variable and dynamic operating envelope functionality depends on tools such as short-term forecasting and optimization engines, and such functionality can only be offered when those tools become operational.

The Commission should therefore pursue a phased roadmap beginning with early-stage implementation activities, including demonstrations, pilots, and/or scalable programs, before directing large-scale implementation. SCE supports continued development of these capabilities, but the implementation schedule should be tied to demonstrated technology readiness, operational validation, and customer participation evidence.

Grid-Edge DERMS for Secondary Constraints

SCE supports continued development of Grid Edge DERMS capabilities for secondary constraints and views them as a valuable component of future flexibility programs. Stakeholder discussions, however, often conflate Grid Edge DERMS and Enterprise DERMS

capabilities. SCE believes the distinction between these architectures remains insufficiently defined, and technical assumptions regarding AMI 2.0, local computation, operating envelopes, and customer-device control require additional development. These systems should be described as an integrated architecture, rather than treating "Grid Edge DERMS" as a stand-alone requirement separate from enterprise systems and planned grid modernization investments.

The Commission should continue technical workshops before adopting prescriptive implementation mandates or specific architecture requirements. These workshops should address the interaction between enterprise DERMS, grid-edge capabilities, AMI 2.0, customer devices, aggregators, OEM systems, communications protocols, cybersecurity, and operational responsibility.

SCE's Feedback on Section 4 Subsection:

Recommendation 4.1 would require the IOUs to provide Limited Power arrangements as the default mitigation for distribution transformer and secondary conductor upgrades. This approach should remain an optional offering rather than the default mitigation measure. SCE generally agrees that customer-controlled load management and operating envelope solutions can provide meaningful alternatives to traditional infrastructure upgrades in certain circumstances. However, the proposal would make these arrangements the default option without sufficient consideration of whether they are cost-effective, operationally appropriate, or desired by the customer. In many circumstances, especially when they bear no cost responsibility for the required grid upgrades, customers may prefer a traditional upgrade rather than a long-term operational limitation that requires installation and maintenance of control equipment. This is particularly important given that distribution transformer and secondary conductor upgrades are often completed on timelines measured in months, not years. Customers who appropriately coordinate project development and energization schedules with SCE can frequently have these upgrades completed by the time they are ready to energize service. As a result, defaulting customers into long-term operational limitations may not represent the most cost-effective or customer-friendly solution when the underlying distribution upgrade can be completed within the normal project development cycle. Customer choice should remain a foundational principle of any flexible connection offering, with Limited Power arrangements available as an option when they align with customer preferences and project circumstances.

SCE is supportive of *recommendation 4.2*, which would direct SCE to implement communication-based Variable Operating Envelope offerings similar to PG&E's Flex Connect program. These capabilities align with SCE's planned evolution toward advanced

DER orchestration and grid management. Implementation feasibility is directly dependent upon deployment of foundational capabilities, including DERMS, short-term forecasting, optimization engines, and communications capabilities that are still under development. SCE recommends that implementation schedules reflect realistic technology deployment timelines rather than prescribed near-term implementation deadlines.

Similarly, SCE supports further discussion of *recommendation 4.3* regarding Dynamic Operating Envelopes and the use of centralized DERMS platforms to address abnormal grid conditions. SCE has identified Dynamic Operating Envelopes as an important future capability enabled through ADMS and DERMS investments, and supports continued exploration through stakeholder workshops and technical discussions before establishing specific implementation requirements. The underlying architecture, operational responsibilities, customer participation models, and integration with broader DER orchestration efforts remain active areas of development and should continue to be coordinated with related discussions occurring in High DER Track 2.

Recommendation 4.4, related to Grid Edge DERMS and ChargeBoost-type programs, raises similar considerations. SCE recognizes the potential value of grid-edge controls to defer certain customer-side upgrades and support more localized management of distribution constraints. Several of the proposal's assumptions regarding Grid Edge DERMS functionality, AMI capabilities, and implementation timelines do not align with SCE's current technology roadmap and require further evaluation. Key enabling capabilities, including AMI 2.0 integration, validated meter-to-transformer connectivity, and expanded grid-edge visibility, are still under development. Importantly, PG&E's ChargeBoost approach leverages an AMI architecture that allows interoperability between AMI 1.0 and AMI 2.0 meters and supports transformer-level visibility through existing communications capabilities. SCE does not currently have comparable functionality. Achieving a similar architecture would require broader deployment of AMI 2.0 capabilities across affected customers, as well as corresponding enhancements to supporting operational and back-office systems. As a result, implementation would involve substantially more time, investment, and system transformation than contemplated by the proposal.

While SCE supports continued advancement of Grid Edge DERMS capabilities, implementation requirements should acknowledge the differences in utility architectures, technology maturity, deployment readiness, and avoid mandating deployment timelines that outpace the development of foundational capabilities and technology readiness.

SCE supports *recommendation 4.5* to continue stakeholder engagement through Energy Division-led workshops focused on Grid Edge DERMS and related operating envelope topics. Workshops offer a mechanism to evaluate emerging technologies, assess

competing architectural approaches, and address unresolved questions regarding capacity sharing, customer access models, local control strategies, AMI integration, and generation interactions before broad implementation requirements are established. Continued stakeholder engagement will help ensure future operating envelope deployments are informed by practical experience, technology maturity, and demonstrated customer value.

Overall, SCE supports the direction of the Section 4 recommendations and the broader goal of leveraging operating envelopes to optimize grid utilization and improve customer outcomes. The Commission should evaluate these opportunities with appropriate implementation guardrails, phased deployment strategies, and realistic timelines that reflect the maturity of the underlying technologies.

Section 5. Cybersecurity Considerations

SCE strongly recommends cybersecurity requirements that are risk-based, scalable, and aligned with existing smart inverter and DER security initiatives. Applying cybersecurity requirements developed for large-scale DER environments to all flexibility offerings may introduce implementation costs and complexity before use cases are fully developed.

Cybersecurity requirements should scale based on resource size, operational impact, and system risk. It is to the benefit of all parties that there be a baseline cybersecurity consideration to ensure that entities responsible for the operation of a device also maintain the burden of compliance for their cybersecurity controls. Baseline cybersecurity controls can ultimately help expedite the connection of new generation assets, and maintain the reliability of the electric grid. These requirements should be developed in coordination with those that they may impact, and SCE supports workshops to vet cybersecurity requirements before imposing broadly applicable baseline requirements, particularly for smaller or less operationally significant flexible connection offerings.

Section 6. Bridging and Non-Bridging Solutions

The recommendations in Section 6 would benefit from a clearer distinction between temporary bridging solutions and long-term non-bridging solutions. While both approaches rely on operating envelopes and managed load concepts, they serve fundamentally different purposes and raise different planning, operational, customer, and regulatory considerations. Bridging solutions are designed to provide temporary service while a known infrastructure upgrade is completed. By contrast, durable and persistent non-bridging solutions contemplate long-term management of customer load and therefore require additional consideration of customer participation requirements, incentives, operational controls, cost recovery, performance monitoring, and long-term system impacts.

SCE firmly supports maintaining bridging FSC offerings that accelerate customer energization and provide near-term customer benefits. The Proposal assumes temporary bridging solutions can readily evolve into durable or persistent non-bridging arrangements. That assumption, however, has not yet been demonstrated through sufficient operational experience. Long-term non-bridging programs raise additional questions regarding customer compensation, permanence of operating restrictions, planning assumptions, reliability obligations, and customer rights and exit options.

The Proposal also appears to treat WDAT As-Available service as an analogy for non-bridging load flexibility. SCE recommends caution with that comparison. WDAT customers generally choose As-Available service because they prefer not to pay for grid upgrades, not because they prefer non-firm service. Many such customers would prefer firm capacity if available without the associated upgrade cost. This analogy is therefore not directly applicable to retail load customers, many of whom do not pay for distribution upgrades and may have no financial reason to accept permanent limitations. In addition, WDAT projects participate in the CAISO market and compliance with their as-available charging schedules is required. WDAT customers that do not adhere to these schedules may be subject to disconnection from the grid and/or other operational limitations. Unlike WDAT As-Available service, Bridging FSC offerings currently do not require the real-time telemetry necessary to verify adherence to prescribed charging schedules or the remote-control infrastructure needed to disconnect customers that fail to comply with those schedules.

The Commission should first establish pilot pathways and evaluation criteria before broadly directing conversion of bridging programs into permanent offerings. Such criteria should include customer value, operational performance, cost-effectiveness, reliability impacts, scalability, and clear rules governing recovery of prudently incurred utility costs. Any pathway that allows customers to transition from bridging to non-bridging service should account for situations where utility planning, engineering, procurement, or construction activities have already been initiated and should protect against inappropriate stranded infrastructure investments resulting from customer-driven changes in project scope or timing.

SCE is concerned that the Proposal does not sufficiently distinguish between "durable" and "persistent" non-bridging solutions. The differences between these concepts are not readily apparent from an operational, planning, or customer implementation perspective. Without more specific definitions, the terms risk creating customer confusion and implementation uncertainty while making it difficult to establish appropriate program requirements, reporting obligations, and forecasting assumptions. SCE recommends that the Commission either provide clearer definitions and eligibility criteria for each category

or designate this issue as a topic for further stakeholder discussion in a future workshop before directing utility implementation.

SCE is also concerned the Proposal overstates the maturity of non-bridging concepts and assumes a straightforward transition from temporary flexibility arrangements to permanent alternatives. A default pathway from bridging to non-bridging service arrangements does not currently exist and should not be presumed without further policy development and stakeholder engagement. While non-bridging solutions may ultimately provide significant customer and system value, important questions remain regarding program design, customer incentives, capacity allocation, technology readiness, and protection against stranded infrastructure investments.

SCE recommends the Commission continue advancing implementation-ready bridging solutions in the near term while further evaluating the operational, economic, and regulatory frameworks necessary to support durable and persistent non-bridging offerings. This sequenced approach will enable continued customer benefits today while ensuring that future non-bridging solutions are designed in a manner that prioritizes safety, reliability, affordability, and long-term scalability.

Section 7. Competition and Market Access

The Commission should develop interoperability requirements through stakeholder workshops and standards-development processes rather than immediate rulemaking mandates. Such workshops should address how interoperability requirements apply across utility systems, aggregators, OEM products, customer-side equipment, communications protocols, and cybersecurity frameworks. They should also recognize that customer choice and vendor competition must be balanced against reliability, operational visibility, data quality, cyber risk, and clear accountability for performance.

Section 8. Real-Time Pricing

The Proposal suggests customers receiving variable or dynamic operating envelopes should be defaulted onto Real-Time Pricing (RTP) rates. At the outset, SCE notes that a key challenge with RTP is the significant data and system capability needed to generate prices. For this reason, SCE has used day-ahead pricing in its dynamic rate applications to date, rather than real-time or day-of pricing. SCE does not currently have the systems and processes needed to offer more frequent pricing updates.

Track 3 discussions have not demonstrated that RTP participation is necessary to make flexible connection programs successful. Customer behavior, responsiveness, and acceptance remain uncertain. SCE has previously supported pilot-based approaches to evaluate compensation and participation structures before widespread adoption.

SCE believes once available, RTP should be an opt-in, rather than a default, until sufficient evidence exists demonstrating customer value, participation benefits, and operational effectiveness.

3. **Section 9 of the proposal summarizes recommendations for Commission action based on the stated goal of the proposal. Do parties find that any additional recommendations are warranted in support of this goal?**

See response to Question 2 for additional recommendations.

4. **For the proposed Advice Letters what, if any, additional implementation or program design elements should be addressed each Advice Letter. Do parties have recommendations on how to consolidate advice letters or make the process more efficient?**

SCE supports the Commission's objective of accelerating implementation of flexible service offerings and other grid flexibility solutions. Advice letters should focus on establishing implementation-ready frameworks while preserving flexibility to incorporate operational experience, technology advancements, and customer feedback over time.

For each proposed advice letter, SCE recommends addressing a common set of implementation elements, including customer eligibility, participation requirements, operational authorities, technology dependencies, performance monitoring, reporting requirements, customer protections, and cost recovery. In addition, advice letters addressing long-term flexibility offerings should clearly define customer obligations, performance expectations, and any incentive structures necessary to support sustained participation. As previously noted, durable and persistent non-bridging arrangements raise different operational and regulatory considerations than temporary bridging solutions and should not be treated as simple extensions of existing FSC offerings.

To improve efficiency and reduce administrative burden, SCE recommends consolidating related flexible service proposals into a limited number of coordinated advice letters built around common implementation frameworks rather than separate filings for each individual use case. For example, offerings that share common customer enrollment processes, technology requirements, reporting frameworks, or operational controls could be addressed within a single filing. This approach would reduce duplicative review, promote consistency across programs, and allow stakeholders and the Commission to evaluate related flexibility offerings holistically.

Finally, SCE recommends that Track 3 advice letter requirements be coordinated with the ongoing Track 2 DER Orchestration effort wherever possible. Many of the implementation

issues under consideration, including customer participation models, performance validation, resource dependability, incentive structures, and technology architecture, are common across both tracks. Aligning these processes will improve regulatory efficiency, avoid duplicative and potentially conflicting proceedings, and support development of a more cohesive flexibility roadmap for California.

5. **Many of the Proposal's recommendations are premised on the goal of affordability and ratepayer savings from greater capacity utilization, speed to power, and deferral or avoidance of upgrade capital expenditure. To realize these goals, quantification of ratepayer costs and benefits will be necessary. For each recommendation how should the IOUs measure, track and report key costs and benefit metrics?**

SCE agrees that measuring ratepayer costs and benefits will be important to evaluating whether the Proposal's recommendations deliver affordability, speed-to-power, increased grid utilization, and infrastructure deferral benefits. Rather than establishing separate reporting requirements for each recommendation, SCE recommends building upon the reporting framework developed through the LCMS Pilot and future Flexible Service Connection implementation activities. The LCMS experience demonstrated that the most meaningful indicators of success were customer energization outcomes, operational performance, and infrastructure deferral benefits. During the pilot, participating customers were energized an average of approximately 20 months earlier than if they had waited for traditional grid upgrades, while maintaining safe and reliable operations.

Consistent with those learnings, SCE recommends a common reporting framework focused on: (1) customer benefits, including customers served and reductions in energization timelines; (2) grid utilization benefits, including capacity enabled; (3) operational performance, including compliance with operating limits and reliability of control and communications systems; and (4) affordability metrics, including implementation costs and realized deferred or avoided infrastructure investment benefits.

For long-term or non-bridging flexible service offerings, reporting should additionally evaluate participation persistence, long-term operational performance, and demonstrated deferral value. Consistent with SCE's Track 2 and Track 3 positions, flexibility should earn broader operational and planning treatment through demonstrated performance and measurable outcomes rather than assumed flexibility potential.

Leveraging the LCMS reporting structure as a starting point will provide the Commission with a consistent evidence base for evaluating customer benefits, grid utilization, and affordability impacts while avoiding duplicative or overly prescriptive reporting requirements.

6. **How should IOUs ensure the existence of bridging solutions, non-bridging solutions, or the change from a bridging solution to a non-bridging solution are timely communicated with the California Energy Commission for forecasting purposes?**

SCE recommends incorporating flexible service reporting into existing forecasting and planning coordination processes between the IOUs and CEC. This approach would provide timely visibility into customer adoption, accelerated load growth, and infrastructure impacts while avoiding duplicative reporting requirements and ensuring that forecasting assumptions remain grounded in actual program experience.

7. **The proposal recommends the Commission direct SDG&E to stand up a static FSC offering that is aligned with the requirements directed in D.26-02-025 for PG&E and SCE.3 a. For SDG&E to implement this proposal, what, if any, modifications to the requirements directed in D.26-02-025 should the Commission consider?**

SCE would note that in D.26-02-025, which was issued February 10, 2026, the Commission determined that SDG&E was not in the same position as PG&E and SCE, in part because it had not previously run any pilots testing flexible service connections. SCE gained a great deal of learning from running its two-year Load Control Management System (LCMS) pilot, including setting up necessary internal systems, so to the extent SDG&E will be required to implement an FSC program in an upcoming decision, it should be given a similar amount of time to establish processes and procedures to support its FSC program. Thus, the tight timing in D.26-02-025, with advice letters due within weeks of its issuance, is likely not practical for SDG&E.

8. **What hardware, software, or data sharing safeguards may be needed to ensure that customers can obtain a flexible connection without being restricted by proprietary arrangements?**

SCE Response:

SCE agrees that customers should be able to obtain a flexible connection without being constrained to a particular vendor, software platform, or proprietary technology ecosystem. To support customer choice while maintaining safety and reliability, the Commission should establish technology-neutral performance requirements supported by industry communications standards, interoperable protocols, and certification-based approaches rather than prescribing specific hardware or software solutions.

SCE's experience in the LCMS Pilot demonstrated that multiple power control system vendors could successfully meet common operational requirements and that nationally recognized standards, such as UL 3141, can streamline deployment while avoiding vendor-

specific approvals. For future communications-based flexible service offerings, the Commission should encourage use of similar industry standards, with SCE strongly supporting IEEE 2030.5, as well as clear data-access, cybersecurity, and customer-consent requirements that allow customers to change technology providers while preserving participation in flexible service programs. This approach promotes customer choice, reduces the risk of proprietary lock-in, and supports a competitive market for flexible service technologies while ensuring utilities retain the visibility and operational capabilities necessary to safely manage the distribution system.

9. Are there any safety concerns that should be highlighted?

While SCE's LCMS Pilot demonstrated that flexible service arrangements can safely accelerate customer energization and improve utilization of existing grid capacity, broader deployment of bridging and non-bridging solutions introduces additional safety considerations that warrant continued attention and careful evaluation. The LCMS experience demonstrated the importance of certified or utility-approved power control systems, ongoing compliance monitoring, and the ability to adjust operating limits as system conditions evolve.

As flexible service offerings become more sophisticated and increasingly rely on customer-owned equipment and communications-based controls, utilities must maintain confidence that control systems reliably operate within approved limits and that sufficient monitoring, telemetry, remote control (including remote disconnection), and operational visibility exist to identify abnormal conditions. Additional attention should be given to equipment failures, communications disruptions, cybersecurity risks, and fail-safe operational protections that ensure customer and grid safety during both normal and abnormal operating conditions. Lessons learned from the LCMS Pilot also highlight the importance of operational tools and visibility capabilities that support timely identification and resolution of potential issues.

SCE believes safety should be evaluated in the context of overall system operating margins and grid resilience. Flexible service arrangements that rely on operating closer to existing system limits may be appropriate under normal operating conditions, but utilities must retain sufficient flexibility to respond to abnormal events, equipment outages, maintenance activities, forecast errors, and contingency conditions. As customer participation increases, there is a risk that reduced operating headroom could limit operational options during unforeseen events, potentially increasing reliability impacts to both participating and non-participating customers. For this reason, flexible service frameworks should preserve adequate safety and reliability margins and include clear

mechanisms to curtail, limit, or suspend flexible operating arrangements when system conditions warrant.

SCE also believes that liability and accountability considerations are an important component of safety. As future flexible service offerings increasingly rely on customer-owned control systems and third-party technologies, clear roles and responsibilities should be established among utilities, customers, equipment manufacturers, installers, and service providers. The Commission should consider how responsibility will be allocated if customer-owned equipment fails to operate as intended, if communications are lost, or if a control system malfunction results in equipment damage or unsafe operating conditions. Clear consequences for non-compliance should also be established to maintain system reliability and protect other customers who may be affected by violations of operating requirements. Doing so will help ensure that flexible service offerings can scale while maintaining safety, reliability, and public confidence.