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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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

TRACK 3 ALL-PARTY WORKSHOP REPORT

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TRACK 3 ALL-PARTY WORKSHOP REPORT

Pursuant to the February 6, 2026 Assigned Commissioner's and Administrative Law Judges' Ruling Providing All-Party Workshop Information and Schedule Modification in Rulemaking 21-16-017, Southern California Edison Company hereby provides the attached Workshop Report from the Track 3 All-Party Workshop held on February 20, 2026.

Respectfully submitted,

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Attachment

Track 3 All-Party Workshop Report

All-Party Workshop Report: Flexible Connections
High DER Track 3 (R.21-06-017)
Workshop Date: February 20, 2026

I. Background

In July 2021, the California Public Utilities Commission (CPUC or Commission) initiated Rulemaking R.21-06-017 to modernize the electric grid for a High Distributed Energy Resources (High DER) future. The proceeding is organized into three tracks addressing distribution planning and execution, operational needs, and smart inverter operationalization and grid modernization. Track 3 builds on earlier Smart Inverter Operationalization Working Group efforts and focuses on improving operational flexibility—the ability of distribution system operators to safely and efficiently leverage existing grid capacity to accommodate increasing levels of electrification and DER adoption.

As DER penetration and load growth accelerate, traditional planning and upgrade approaches alone may not be sufficient to meet customer demand in a timely and cost-effective manner. In response, the Commission has sought input on flexible connections, including the use of operating envelopes and other operational tools that can enable customers to interconnect or energize under time-varying or conditional capacity limits while maintaining grid safety and reliability.

On November 3, 2025, the Assigned Commissioner issued a ruling requesting additional party input on the readiness of technologies such as Advanced Distribution Management Systems (ADMS), Distributed Energy Resource Management System (DERMS), Advanced Metering Infrastructure (AMI), aggregators, and communications protocols to support flexible connections, as well as the potential use cases for these tools as either bridging solutions (temporary import limits that allow partial load energization pending completion of planned infrastructure upgrades) or nonbridging solutions (import limits that provide a service to the utility or that allow the customer avoid costs that the customer would otherwise incur). The ruling also emphasized the importance of understanding costs, benefits, and implementation considerations without relying on direct customer compensation.

II. Introduction

The High DER Track 3 All-Party Workshop on Flexible Connections was held on February 20, 2026, to further develop the record on the topics identified in the Assigned Commissioner's ruling. The workshop brought together CPUC staff, investor-owned utilities (IOUs), community choice aggregators, DER advocates, and other stakeholders to share perspectives, technical experience, and policy considerations related to flexible connections and operating envelopes.

The workshop was structured around eight focus areas, including the use of ADMS and DERMS to provide variable operating envelopes; the role of AMI data in enabling faster connections, particularly for customers interconnecting at the secondary level; approaches to managing shared secondary constraints; the appropriate use of IEEE 1547 (Standard for Interconnecting Distributed Resources with Electric Power Systems) for inverter capabilities; the role and definition of aggregators; communications protocols; alignment with dynamic rates; and customer election of nonbridging solutions.

Across these discussions, participants explored where flexible connections may provide meaningful value; how they could be implemented at scale; and where additional pilots, analysis, or Commission guidance may be needed. While there was broad agreement on the importance of operational flexibility to support electrification and DER growth, parties expressed differing views on readiness, appropriate use cases, and the extent to which customers will adopt flexible connections as long-term alternatives to traditional infrastructure upgrades.

This report summarizes the key points raised by each party, areas of alignment and divergence, and highlights takeaways and potential next steps to inform subsequent phases of the Track 3 proceeding.

III. Purpose and Scope of the Workshop

The February 20, 2026 All Party Workshop was convened by the CPUC Energy Division pursuant to the Assigned Commissioner's Ruling to gather stakeholder input on flexible connections and operating envelopes under Track 3 of the High DER proceeding. The workshop focused on identifying near and medium-term use cases (through ~2030), assessing technical and operational readiness, and exploring regulatory considerations for enabling flexible connections as either bridging or nonbridging solutions, without direct customer compensation. Note that due to the latter condition, presenters did not provide any in-depth analysis of a compensation-based approach.

The discussion was organized around eight topics identified in the ruling, including the use of ADMS/DERMS, AMI data, aggregator roles, communications protocols, dynamic rate alignment, and customer election of non-bridging solutions.

IV. Summary of Perspectives by Party

a. CPUC Energy Division

Energy Division explained that the workshop was intended to build on prior Track 3 work concerning operational flexibility and to further develop the record regarding pathways for implementing flexible connections for DERs and load. Energy Division further stated that the November 3, 2025 Assigned Commissioner's Ruling requested additional comment on: technology readiness; implementation of priority use cases under normal operations; potential use cases under abnormal conditions; and the extent to which flexible connections could serve as a longer-term solution in addition to a bridge-to-wires solution.

Energy Division identified four principal workshop objectives: (1) to clarify the primary use cases for flexible connections; (2) to identify the distribution system constraint or operational problem being addressed; (3) to assess utility, customer, and industry readiness to implement and scale solutions; and (4) to evaluate the costs and benefits to utilities, participating customers, and ratepayers. Energy Division also framed the workshop around specific topics, including ADMS/DERMS-enabled operating envelopes, single-phase and shared-secondary applications, smart inverter functionality, communications and CSIP issues, dynamic rates, and customer election of non-bridging operating envelopes.

Energy Division further distinguished between bridging and non-bridging flexible connection use cases. Bridging solutions were described as temporary operating limits that may allow a customer to interconnect sooner while awaiting a planned wires upgrade. Non-bridging solutions were described as ongoing non-firm arrangements not tied to a planned upgrade and potentially applicable where a wires solution is not planned or is not cost-effective. Energy Division also stated that direct customer compensation was not the focus of the workshop, while recognizing that non-cash forms of customer value remained relevant.

The use cases, and limitations on the scope, were identified in the following table from Slide 11 of the CPUC presentation:

Bridging Solution: Load Use Cases

Primary Use Case	*Customer vs. Utility Value Exchange*	*Example*
Temporary import (load) limits to facilitate electrification/ energization	**Utility Value:** Speed to power, unlock existing load capacity, efficient capacity utilization **Customer Value:** Faster connections	Offer **temporary** variable operational envelopes to customers Install load management devices at customer premise Use DERMS/ADMS to effectively manage operational limits

Non-Bridging Solution:

Primary Use Case	*Customer vs. Utility Value Exchange*	*Example*
On-going import (load) limits to facilitate electrification and operational flexibility	**Utility Value:** Unlocks non-firm flexible capacity, defer or avoid future grid upgrades **Customer Value:** Flexibility can lower electric bills, avoid customer equipment, e.g. service panel upsizing, facilitates electrification	Offer **on-going** variable operational envelopes to customers Install load management devices at customer premise Use DERMS/ADMS to effectively manage operational limits

- 'Value' refers to savings from distribution of system-level avoided costs for the grid/utilities (e.g., solutions that defer upgrades) or avoid customer costs (e.g., panel upsizing) Other values include time savings for customers or speed to power for utilities (which brings revenue sooner.)
- Non-Bridging solutions that enable direct financial compensation for customers are not being explored at this time. Non-monetary exchanges may include enabling technologies that unlock savings greater than their cost.

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Staff emphasized that the workshop was not intended to select a preferred solution, but rather to identify where flexible connections are most viable, where additional proof is needed, and how these tools might inform future Commission decisions.

b. PG&E

Pacific Gas and Electric Company (PG&E) presented its experience implementing DERMS enabled Flexible Service Connections through its Flex Connect program, emphasizing that flexible connections are already being used in production to address primary distribution system constraints. PG&E described Flex Connect as an operational tool that is actively supporting customer interconnections today, rather than a purely conceptual or pilot-stage approach.

PG&E explained that its current use cases include the application of variable operating envelopes on primary distribution feeders to manage both load and generation, enabling customers to interconnect or energize while remaining within system constraints. PG&E also described a pilot focused on testing increased scale and demonstrating meaningful improvements in speed-to-power, with the objective of validating the operational and customer benefits of flexible connections as compared to traditional upgrade-driven approaches. In addition, PG&E noted select nonbridging applications, particularly for electric vehicle charging customers and certain generation projects, where operating envelopes can serve as longer-term alternatives to infrastructure upgrades.

PG&E emphasized the importance of IEEE 2030.5 and the Common Smart Inverter Profile (CSIP) as foundational elements of its flexible connection approach. PG&E stated that IEEE 2030.5/CSIP supports key requirements for reliability, cybersecurity, and fail-safe operation, and enables consistent, standards-based communication between DERMS and customer equipment. PG&E characterized protocol standardization as critical to scaling flexible service connections while maintaining operational integrity.

With respect to secondary-level constraints, PG&E cautioned against reliance on AMI 1.0 data alone to generate operating envelopes, citing concerns related to data latency and limited ability to capture load diversity at the secondary level. PG&E indicated that these limitations constrain the feasibility of near-term secondary-level operating envelopes based solely on existing AMI 1.0 capabilities.

PG&E discussed ongoing EPIC-funded pilots that are exploring the use of AMI 2.0 capabilities and cloud-based aggregation approaches to address secondary-level constraints. These efforts include using AMI 2.0 connectivity solutions to accelerate residential electrification by avoiding customer costs associated with panel upgrades and by deferring service upgrades such as service wires, secondary conductors, and service transformers. In parallel, cloud-based aggregation approaches are being evaluated as a means to defer service transformer replacement.

PG&E has two projects which are developing the capability to defer secondary & service transformer upgrades:

EPIC 4.02 – AMI 2.0 Edge Management (EVs & Any Electrification Load via Smart Panel)

Purpose: Connect customers immediately without upgrades

Method:
1. AMI 2.0 meter in real-time monitors load and voltage on the secondary
2. An operating envelope is calculated on the meter and sent locally
3. The EV charger or smart panel adjusts its output to the available capacity

EPIC 4.04 – Cloud Aggregated Management (Electric Vehicles)

Purpose: Defer secondary transformer replacements

Method:
1. An EV is enrolled in a cloud aggregation
2. A service transformer forecast is generated
3. The vehicle charging is rescheduled based on the transformer limits while staying within the off-peak window

		AMI 2.0	Cloud Mgmt
Customer Value	Panel upgrade avoidance	✓	✗
	Service upgrade avoidance	✓	✗
Grid Deferral Value	Service wire	✓	✗
	Secondary conductor	✓	✗
	Service transformer	✓	✓
Solution Capabilities	Load management	✓	✓
	Voltage management	✓	✗
	Software only	✗	✓

Above: PG&E approaches to residential customer electrification enablement and secondary grid deferrals

Finally, PG&E stated that customer participation in Flex Connect to date has been driven primarily by faster access to additional power for new loads and avoided upgrade costs for battery energy storage rather than monetary compensation. PG&E indicated that these non-cash benefits have been sufficient to motivate participation in current use cases and have informed the design and targeting of Flex Connect deployments.

c. SCE

Southern California Edison Company (SCE) reiterated its support for the objectives of High DER Track 3 and emphasized the importance of advancing implementation-ready operational solutions that enable flexible interconnections while maintaining safety, reliability, and affordability. SCE framed Track 3 as an opportunity to align policy direction with the realities of grid operations and the pace of grid modernization underway.

SCE provided an overview of the technical approach working towards deploying dynamic operating envelopes to enable flexible interconnections and described its ongoing deployment of integrated Advanced Distribution Management System (ADMS) and Distributed Energy Resource Management System (DERMS) capabilities, highlighting how these capabilities are intended to enable the grid to operate closer to physical limits and unlock operational flexibility as DER penetration increases. SCE presented a phased roadmap for deploying DERMS and related grid management capabilities.

SCE indicated plans to provide 24-hour lookahead operating envelopes and to deploy real-time dynamic operating envelopes across feeders as capabilities mature. SCE emphasized that operating envelopes rely on accurate system models and data, and that additional instrumentation should be driven by identified gaps through system analysis.

SCE discussed challenges associated with secondary level constraints and the potential role of AMI enabled solutions, particularly as future AMI capabilities are deployed. SCE noted that enhanced visibility at the secondary level could help manage service transformer loading, avoid or defer customer panel and service transformer upgrades, and reduce costs for customers. SCE cautioned that purely statistical approaches to estimating operating limits have limitations and should be applied carefully.

With respect to smart inverter functionality, SCE noted that many IEEE 1547 functions, including Volt VAR and Volt Watt, have already been incorporated into Rule 21. SCE expressed openness to stakeholder discussion on potential refinement, while emphasizing that any changes must be technically feasible, deliver clear value, and account for impacts to customer real power production and equipment certification processes.

SCE described the role of aggregators in functional terms, focusing on their potential to bundle DERs or flexible loads, translate IEEE 2030.5 signals to device specific protocols, and facilitate compliance with operating envelopes. SCE emphasized that utility operational needs are focused on aggregate performance at the interconnection level rather than visibility into individual devices, and that aggregation models may vary depending on use case.

Regarding communications protocols, SCE stated that existing IEEE 2030.5 and CSIP profiles are sufficient to support implementation of VOEs and DOEs. SCE cautioned against protocol modifications that could introduce additional cost or complexity without clear operational benefit.

SCE also addressed the relationship between operating envelopes and dynamic rates. From SCE's perspective, operating envelopes are control signals designed to manage physical system constraints, while dynamic rates are pricing mechanisms intended to influence customer behavior. SCE emphasized that these tools serve different purposes and should be evaluated independently, even if deployed in parallel.

Finally, SCE presented a conceptual framework for flexible service connections and load flexibility, distinguishing both between temporary and permanent solutions, and between solutions implemented pre-energization or post energizations, for four distinct concepts as detailed below. Each of the four concepts offers a different mix of value to customer and value to grid.

- *Temporary solution, implemented prior to energization*: This is the classic "bridge-to-wires" solution. Customers gain value through faster energization; no monetary incentive is offered.
- *Permanent solution, implemented prior to energization:* The value to the customer here is a reduction interconnection costs (i.e., costs allocated to the customer under Rules 15 and 16). The value to the grid may be a deferral of a grid upgrade. (Note, however, that the duration of the deferral will depend on other load growth).
- *Temporary solution, implemented after energization:* This is essentially a grid orchestration program. The value to the grid would vary based on grid needs in that area, including constraints that may be further upstream. The value would be contingent on sufficient total flexibility across customers in the area served by the constrained section. There is no obvious value to the customer so a monetary incentive may be required.
- *Permanent solution, implemented after energization:* This is essentially permanent enrollment in an orchestration program. There is no obvious value to the customer so a monetary incentive may be required.

SCE noted that its current focus is on temporary bridging solutions to accelerate energization, as well as developing and implementing pilots for orchestration programs. other configurations remain conceptual and raise considerations related to cost recovery, asset utilization, and customer incentives.

d. SDG&E

San Diego Gas and Electric Company's (SDG&E) presentation focused on prerequisites for readiness and implementation. SDG&E stated that its prepared remarks would address SDG&E's grid modernization vision, ADMS/DERMS-enabled variable operating envelopes, and IEEE 2030.5 communications and CSIP considerations.

SDG&E's principal message was that it is not currently positioned to deploy a standardized, systemwide dynamic operating envelope offering as there is no near-term need. SDG&E stated that any near-term application would be limited to targeted proof-of-concept or pilot-scale efforts with clearly defined scope, objectives, and measurable outcomes. SDG&E further stated that its participation in the workshop was intended in part to gather information from utilities and stakeholders that are further along in this area.

SDG&E stated that its vision is to build a flexible, customer-centric grid that supports customer choice and technology adoption while maintaining affordability and reliability, and that doing so requires prioritizing the foundational capabilities necessary to operate increasingly dynamic distribution systems safely and predictably.

In later discussion, SDG&E reiterated that its present status is best described as proof-of-concept. The need for a standardized, scalable, operating envelope offering has not been demonstrated. When such a need is evident, additional functional enablement – particularly with respect to data and telemetry readiness, modeling and forecasting capabilities, operational workflows, and verification and enforcement – will be required. SDG&E also noted that any future work in this area should be aligned with DERMS deployment in order to avoid duplicative solutions.

Accordingly, SDG&E's presentation is best summarized as supportive of continued exploration of flexible connections, while making clear that major commitments are contingent on demonstrated need and benefits. When such need and benefits become apparent, additional foundational work is required before SDG&E could support a standardized systemwide offering.

e. IREC

Interstate Renewable Energy Council (IREC) emphasized the importance of clarity, analytical rigor, and transparency in evaluating flexible interconnection and operating envelope approaches under High DER Track 3. IREC framed these elements as essential to ensuring that emerging tools and frameworks are applied consistently and can be meaningfully compared across use cases and jurisdictions.

IREC highlighted the need to clearly define DERMS and distinguish among different DERMS architectures and communications approaches as they are applied across Track 3 use cases. From IREC's perspective, greater clarity regarding the roles and capabilities of enterprise DERMS, grid-edge systems, and aggregators would help stakeholders better assess where particular solutions are appropriate and scalable.

In discussing low-voltage and secondary distribution systems, IREC expressed interest in further exploration of model-free hosting capacity analysis methodologies, particularly approaches that leverage existing AMI data. IREC pointed to international experience and alternative analytical techniques as potential avenues for improving visibility and decision-making on secondary networks where traditional system models may be incomplete or costly to develop.

IREC also emphasized the importance of transparent and comparable cost-benefit analysis across alternative flexible interconnection and operating envelope methodologies. IREC indicated that consistent evaluation frameworks are necessary to understand tradeoffs among different approaches, avoid premature standardization, and ensure that policy decisions are informed by comparable data on costs, benefits, and implementation readiness.

IREC supported further evaluation of autonomous Volt/Watt as a potentially low-cost, non-bridging flexibility tool for voltage-constrained locations, while emphasizing the need for careful analysis of aggregate system impacts and transparent comparison with operating envelope-based approaches.

IREC expressed support for examining both static and variable operating envelopes as potential non-bridging tools, particularly where such approaches could provide near-term flexibility without requiring immediate infrastructure upgrades. IREC encouraged continued evaluation of these tools across a range of system conditions before narrowing the set of solutions pursued under Track 3.

f. CalCCA

California Community Choice Association's (CalCCA) presentation emphasized that flexible service connections align closely with the mission and operating model of CCAs because CCAs are community-based, not-for-profit entities that already run DER and customer programs aimed at reliability, demand flexibility, electrification, and customer bill savings. The presentation highlighted that CCAs serve 229 communities and more than 16 million Californians.

CalCCA highlighted that CCAs are well positioned to scale flexible service connections for single phase customers. CalCCA expressed support for possible joint IOU/CCA pilot opportunities for secondary-service customers, particularly where grid-edge DERMS tools offered through CCA programs could provide a cost-effective means of reaching residential and commercial customers on the secondary system.

CalCCA expressed support for enabling OpenADR communications in addition to IEEE 2030.5; stating the two are complimentary not "either or." On the topic of non-bridging solutions, CalCCA suggested that IOU and non-IOU solutions should be considered. Further, proposed non-bridging solutions should be subject to cost-effectiveness evaluations and equity considerations.

On dynamic rates, CalCCA expressed caution. Cal CCA stated that customers on variable operating envelopes should be informed of available rate options, including dynamic rate pilots or offerings, but should not be automatically enrolled in such rates. CalCCA explained that currently available dynamic rates remain nascent, are still shadow-billed, and are supported by limited evaluative data. CalCCA further stated that CCAs would need lower-latency, billing-quality hourly interval data in order to implement and evaluate CCA-specific hourly or sub-hourly generation rates effectively. CalCCA therefore urged the Commission to advance flexible service connections without the added uncertainty associated with defaulting customers onto dynamic rates.

g. VGIC

Valley Grid Integration Coalition (VGIC) emphasized that non-bridging Flexible Service Connections (FSCs) should be elective and structured as a bottom-up mechanism for customers interested in proactively supporting the grid.

VGIC highlighted the need to recognize and value customer contributions under non-bridging FSCs. VGIC stated that customers incur real, upfront costs to implement non-bridging strategies and that, without some form of incentive or compensation, there is limited value in advancing discussion of non-bridging FSCs. VGIC emphasized that incentive structures should be designed to protect ratepayers by ensuring that total incentive budgets remain below the value of avoided or deferred system upgrades, thereby maintaining a clear net benefit.

VGIC emphasized that transparent data collection and performance tracking are necessary to understand how non-bridging FSC policies affect customer behavior, grid outcomes, and cost effectiveness.

VGIC addressed the role of dynamic rates, noting that such rates remain relatively nascent and warrant further evaluation. While expressing interest in additional learnings related to dynamic pricing, VGIC emphasized the importance of preserving options for customers who may not be interested in, or eligible for, dynamic rates. VGIC stated that customers providing grid value through non-bridging FSCs should have access to alternative mechanisms for recognizing that value, independent of participation in dynamic rate structures.

V. Conclusion

The workshop discussion highlighted broad agreement that Flexible Service Connections (FSC) represent a significant opportunity to support near-term customer energization and manage distribution system constraints, while potentially avoiding or deferring infrastructure investments across both primary and secondary systems. Participants emphasized that meaningful value exists in both domains, with applications spanning load growth from electrification and EV adoption, as well as secondary system constraints at the service panel and transformer level. Bridging solutions were widely viewed as a practical and immediately deployable approach, while nonbridging solutions were generally characterized as longer-term and dependent on additional analytical, technical, and regulatory development.

Looking ahead, participants identified several priorities for advancing the proceeding. These included the need for improved cost and benefit analysis supported by real-world data, expanded use of pilots and incentives to inform customer behavior and value, and clearer pathways for both load and generation use cases, including the role of aggregators. Data access, communications protocols, and alignment on DER coordination capabilities were repeatedly cited as foundational enablers. Parties also emphasized the need for regulatory clarity—particularly with respect to the obligation to serve and compensation mechanisms—to support appropriate tradeoffs between customer service, system reliability, and infrastructure deferral. Collectively, the discussion reflected a shared interest in establishing a clear near-term path for FSC deployment while laying the groundwork for scalable, data-driven, and technology-enabled solutions over the longer term. The workshop record will inform the Commission’s continued consideration of Track 3 issues and next steps in the proceeding.

Appendix A - Q&A Transcription and Summary by Session

A. Opening Framing Q&A (Energy Division / Commission)

Q1 – Scope of "No Compensation" Boundary

Asked by: IREC

Question (transcribed):

"Why is the Commission not currently considering compensation mechanisms for non-bridging solutions? Additional explanation on the rationale would be helpful."

Response (summary):
Energy Division clarified that, at this stage, the focus is on non-bridging solutions that do not rely on direct monetary compensation. ED encouraged consideration of alternative value exchanges and non-compensatory arrangements that reflect real system value. While compensation mechanisms are not ruled out, ED emphasized the importance of first exploring intuitive and lower-complexity value propositions as an initial step in this emerging space. The near-term objective is to identify and pursue "low-hanging fruit" opportunities, with the understanding that monetary compensation frameworks may be more appropriately addressed in the longer term as the market and regulatory context mature.

B. PG&E Presentation Q&A

Q2 – AMI, Aggregators, and Expansion Path

Asked by: Commissioner / ALJ

Question:

"Are your pilots mainly focused on utility-to-customer information today? How do aggregators fit in, and how does AMI 2.0 change the ability to expand flexible service connections to customers and third parties?"

Response:
PG&E explained that current flexible service connections focus on primary distribution constraints, while AMI 2.0 pilots target secondary residential connections. These efforts are not yet integrated but could be in the future. Communications rely on standardized

protocols to enable scalability. The pilot infrastructure is designed to be reusable, with initial deployments prioritized based on customer need.

Q3 – Coordination with CAISO

Asked by: Commissioner

Question:

“As this expands, do you see integration with CAISO and consistency between transmission and distribution operations?”

Response:
PG&E described ongoing coordination with CAISO on data sharing and forecasting. Lessons from distribution-level flexibility may inform future approaches for transmission-connected loads. AMI 2.0 and smart panel integration were described as foundational for customer-level visibility.

Q4 – EPIC Reports and AMI 2.0 Data

Asked by: ALJ

Question:

“When will the EPIC reports be available? Is the five-minute load data coming over, and will it be an open standard?”

Response:
PG&E expects substantive EPIC results by late 2026 or early 2027, with possible interim findings. Five-minute data is exchanged locally via the AMI mesh network, while real-time customer access is enabled via Matter over WiFi. Only meters serving new flexible loads require replacement.

Q5 – Cost of IEEE 2030.5 Enablement

Asked by: Environmental Defense Fund

Question:

“Are you tracking the cost to customers to install and commission IEEE 2030.5 equipment? Do you expect costs to fall as more vendors enter?”

Response:
PG&E stated it does not systematically track all customer costs but has reviewed examples. Costs decline as the vendor ecosystem matures, particularly when functionality is embedded into existing software platforms. Custom, one-off installations remain more expensive.

Q6 – Import vs. Export Envelopes for Storage

Asked by: Vehicle-Grid Integration Council (VGIC)

Question:

"For long-term battery storage sites on dynamic envelopes, are limits applied to imports, exports, or both?"

Response:
PG&E clarified that current sites use either import or export limits, not both simultaneously, though the system can technically support both.

Q7 – Enterprise vs. Grid-Edge DERMS

Asked by: CalCCA

Question:

"Can you distinguish between enterprise DERMS and grid-edge DERMS, and when third-party providers will be able to respond to signals?"

Response:
PG&E explained that enterprise DERMS currently connects directly to sites or gateways, aggregators, or via cloud-based solutions. A more standardized interface for third-party aggregators is under development and will be open and nonexclusive. PG&E confirmed that CCA customers would be supported.

Q8 – Aggregator Exclusivity and Batteries

Asked by: Lunar Energy

Question:

"Will the aggregator interface be exclusive? What role do batteries play in secondary constraint management?"

Response:
PG&E confirmed the interface will be open to multiple aggregators. Home batteries are part of the longer-term roadmap but not yet implemented. The DERMS aggregator interface is being designed to support all aggregable DERs.

Q9 – Monitoring for Large FlexConnect Sites

Asked by: IREC

Question:

"Is monitoring already in place for larger FlexConnect customers, or is it built per site?"

Response:
PG&E stated that telemetry and dispatch capabilities are commissioned per site. Existing SCADA points are used where available; modeled constraints require additional development.

C. SCE Presentation Q&A

Q10 – Status of Non-Bridging Solutions

Asked by: VGIC

Question:

"Aside from bridge-to-wires, is SCE pursuing any of the non-bridging options shown?"

Response:
SCE stated it is currently pursuing only bridging solutions; other options remain conceptual.

Q11 – Risk of Switching from Bridging to Permanent

Asked by: Environmental Defense Fund

Question:

“If a customer later opts for a permanent solution after a bridging upgrade is built, isn’t that a sunk cost risk?”

Response:
SCE responded that under-utilization risk exists but investments were made based on customer requests. The utility should not be penalized for acting on good-faith planning assumptions.

Q12 – Export Limits and CSIP

Asked by: IREC

Question:

“CSIP lacks an export limit command set. How are export envelopes handled?”

Response:
SCE explained it uses the Australian CSIP variant, which includes export limits.

Q13 – DSO–TSO Coordination

Asked by: CAISO

Question:

“How will operating envelope capacity be coordinated across distribution and transmission?”

Response:
SCE acknowledged increasing complexity and the need for better coordination tools. Energy Division noted this is a priority topic for future workshops.

Q14 – Load Forecasts and SCADA

Asked by: unattributed

Question: “How does SCE develop load forecasts without relying on SCADA data?”

Response:

SCE explained that its forecasts are informed by multiple data sources, including the California Energy Commission’s Integrated Energy Policy Report (IEPR), customer-provided information (such as project location, size, and submitted data), and known pending load requests. These inputs are combined to form the utilities' 10-year planning forecasts, which serve as the basis for planning assumptions.

Q15 – Aggregator Visibility

Asked by: CalCCA

Question: "With respect to the use of aggregators, does SCE have visibility at the individual inverter or device level, or only at the aggregated response level?"

Response:

SCE stated that communications occur through the aggregator, which translates IEEE 2030.5 signals into the protocols used by individual inverters. SCE indicated that while it seeks information on DER operational performance, utilities are primarily focused on system-level or aggregated responses rather than individual device-level control.

Q16 – Modeling of Secondary

Asked by: IREC

Question: "SCE has discussed plans to model the entire distribution system, including secondary and low-voltage networks. What use cases will this modeling support, and what is the anticipated deployment timeline?"

Response:

SCE identified multiple use cases for full-system modeling, including support for operating envelopes (both variable and dynamic) and real-time operations to improve system awareness and optimization. SCE indicated that much of this capability is expected to be developed during Phase 2, with implementation anticipated around 2027–2028.

Q17 – Obligation to Serve

Asked by: CalPA

Question: "In the context of Flexible Service Connections (FSC), how does the obligation to serve influence SCE's interactions with customers and their potential load?"

Response:

SCE stated that it operates under a fundamental obligation to serve. Within that framework, SCE seeks to use the grid as efficiently as possible to meet customer needs, including through the use of static or dynamic FSCs where appropriate, while minimizing grid investments. SCE referenced prior Commissioner remarks regarding energization and customer interactions in relation to the obligation to serve.

Q18 – Proactive FSC Customer Engagement

Asked by: Anthony Abdallah

Question: "In the four-quadrant framework discussed, what incentives would motivate a customer to remain under a permanent bridging solution? Why does SCE not proactively offer customers the option to remain on a permanent flexible connection to avoid upgrades?"

Response:

SCE explained that its response to Topic 8 was framed by the workshop ruling, which focused on the ability to move between quadrants, rather than on proactively offering permanent bridging arrangements. SCE emphasized that IOUs are not penalized for allowing customers to transition from bridging to non-bridging solutions after infrastructure investments have been made. SCE further noted that a process for customers to remain under a permanent limitation does not currently exist, and therefore there is no such option available today. SCE stated that if such a process were developed, customer incentives would be a central consideration (e.g., incentives related to panel upgrades or Rule 15 provisions).

Q19 – WDAT Projects

Asked by: US Solar

Question: "Under the Rule 21 proceeding, WDAT projects can sign up for limited generation profiles. What additional methods or processes would SCE need to offer for WDAT projects, and is this capability currently available, including for export?"

Response:

SCE stated that WDAT projects currently have the capability to operate under charging limitations, with developers provided charging schedules to avoid triggering grid upgrades.

However, SCE clarified that this capability is not available for exporting generation, as the WDAT tariff does not support export functionality.

Q20 – Rule 21 Transfer

Asked by: IREC

Question: “Is it possible for a project to apply under Rule 21, obtain a limited generation profile, and then transfer to a WDAT interconnection agreement?”

Response:

SCE indicated that it would need to further evaluate the feasibility and process implications of such a transfer.

D. SDG&E Presentation Q&A

Q21 – Meaning of Static Operating Envelopes

Asked by: IREC (chat)

Question:

“What do you mean by static operating envelopes?”

Response:
SDG&E clarified these are fixed charging profiles provided to large DERs to avoid constraints.

E. Non-Utility / Cross Panel Q&A

Q22 – Largest Opportunity Area

Asked by: General audience

Question:

“Where is the biggest opportunity—primary or secondary, bridging or non-bridging?”

Response:
PG&E emphasized immediate readiness of primary-level bridging. CCAs highlighted secondary-level potential. Consensus that non-bridging needs more review.

F. Protocol-Focused Q&A

Q23 – OpenADR vs. IEEE 2030.5

Asked by: Robby Simpson - Metrics

Question:

"What's missing from IEEE 2030.5 that makes OpenADR more scalable?"

Response:
CalCCA cited OpenADR's cost-effectiveness and suitability for demand flexibility. Agreement that protocol coordination is needed.

G. Closing Q&A

Q24 – Addressable Opportunity for Flexible Service Connections (FSC)

Asked by: Energy Division

Question:

"Considering the range of solutions discussed, what is the largest addressable opportunity for Flexible Service Connections (FSC), in terms of megawatts of savings or avoided infrastructure costs (e.g., transformers), across primary and secondary systems, including both bridging and non-bridging applications?"

Response:

PG&E:
PG&E stated there is significant opportunity across both primary and secondary systems, as reflected in the Electric Infrastructure Strategy (EIS) Phase 2 study, with potential savings in the billions of dollars. On the primary system, the key question is how to scale FSCs to accommodate all forms of load growth across customer classes, including electric vehicles and home electrification. On the secondary system, PG&E identified two major buckets of avoided costs—at the service panel and service transformer levels—and noted that pilots are underway to evaluate scalable approaches to capture these benefits.

VGIC:
VGIC reiterated the perspectives and opportunities described earlier in its presentation.

IREC:
IREC emphasized the need for cost-benefit analysis on the record in this proceeding, supported by real data. IREC noted that while there is discussion of value, there are currently limited cost data available, and the proceeding should address how costs and benefits are assessed and weighed.

CalCCA:
CalCCA agreed that there are meaningful opportunities on both primary and secondary systems. CalCCA highlighted that Community Choice Aggregators (CCAs) are well positioned to leverage customer-side resources, particularly on the secondary system, through programs aimed at reducing future Resource Adequacy obligations and providing load capacity during peak periods. CalCCA emphasized that without sufficient system visibility, conflicts may arise, and that CCAs have a unique role in coordinating secondary-system solutions.

SCE:
SCE agreed that both primary and secondary opportunities are important, but stressed that sequencing matters. SCE stated that its near-term priority is energizing customers, including through bridging solutions, while continuing work to prepare DERMS capabilities. SCE noted that significant questions remain for non-bridging solutions and should continue to be addressed, but emphasized the importance of deploying available tools now to serve customers.

CCA (general):
A CCA participant agreed that the proceeding should begin with bridging solutions, noting that IOUs do not yet have firm plans for grid-edge DERMS capabilities. The participant emphasized the need for clearer timelines, plans, and certainty regarding what the proceeding aims to accomplish and when.

Q25 – Priorities for Advancing the Proceeding

Asked by: Energy Division

Question:

“What one or two priorities should this proceeding focus on to move forward**,** including the desired end state and key steps needed to achieve it?**”**

Response:

VGIC:

VGIC recommended directing funding toward incentive programs to support equipment installation and data collection, including potential use of EPIC funds for deployment, piloting, and customer experience evaluation. VGIC emphasized the importance of understanding customer incentives for non-bridging solutions and the resulting avoided costs, as well as collecting data through authorized pilots to assess customer value and engagement.

Tesla:

Representing customer-side perspectives, Tesla expressed strong support for bridging solutions as a near-term approach, while viewing non-bridging solutions as a longer-term objective. Tesla emphasized the importance of customer-friendly technology adoption, noting that readiness is required on both the grid and customer sides. Tesla highlighted the large market potential in EV charging and underscored the need for a supportive regulatory and operational environment. Tesla encouraged leveraging existing FSC offerings first, then expanding over time.

IREC:

IREC noted that discussions of bridging and non-bridging solutions should more explicitly include generation use cases. IREC stated that non-bridging approaches may already be viable for generation, given existing financial incentives, and emphasized the need to distinguish between load and generation customers. IREC noted that the choice between dynamic and static approaches may depend on the use case, and that static options should remain under consideration where appropriate.

ED:

The Energy Division confirmed that generation is within scope, acknowledged the complexity of coordinating across multiple workstreams, and encouraged parties to provide comments on generation-related ideas.

CalCCA:

CalCCA emphasized the need to resolve data access and availability issues, including identifying data needs and establishing pathways to access that data. CalCCA called for clearer pathways to deploy generation resources quickly, forums to address communications protocols, and strategies to leverage grid-edge DERMS capabilities beyond enterprise DERMS. CalCCA also emphasized the importance of aligning compensation mechanisms for grid services to avoid conflicting or duplicative provider actions.

SCE:

SCE noted that generation issues are typically addressed under Rule 21 and suggested alternative terminology for aggregators, such as “demand and DER coordinator,” “demand flexibility coordinator,” or “demand management coordinator.”

PG&E:

PG&E raised questions regarding the obligation to serve and how marginal capacity is treated, particularly at extreme load conditions (e.g., the 99th percentile). PG&E explained that current interpretations require serving all load, even where limited curtailment might be imperceptible to customers, constraining the ability to defer infrastructure upgrades. PG&E stated that addressing this issue requires regulatory guidance from the Commission to support appropriate societal tradeoffs, rather than unilateral utility or vendor action.

Appendix B - Q&A from Chat

1. **11:20 AM — Roberts, Thomas**
   Q/Issue raised: "PG&E slide with EPIC 4.02 and 4.04 details is not in the slide deck circulated. Hopefully an update will be provided to participants."
   Response (Gabriel Petlin, CPUC; 11:28 AM): "PGE sent this deck to the HDER Service list at 3:45 pm Thursday. We will share it again after the workshop. "Slides are available at __________.]

2. **11:42 AM — Nishant Bilakanti**
   Q: "Will PG&E pilot the grid-import limiting solution to avoid service upgrades?"
   Response (transcript; 02:23:57–02:24:45): The facilitator read the question aloud; the presenter said they were "not familiar with that exact tool" and invited Nishant to connect afterward so they could "look into it."

3. **11:49 AM — Woon Jung (CPUC)**
   Q: "Do you need an AMI 2.0 meter for every individual customer, or just one per service transformer?"
   Response (transcript; 02:24:45–02:25:06): "Just one AMI meter per customer that is being connected while deferring a panel or service upgrade. The minimum to virtualize a service transformer is one per service transformer."

4. **11:56 AM — Golson, Cydnie "Cyd"**
   Q: "If I understand this correctly... The virtual transformer idea was mentioned - is this the pathway to integrate the secondary-level operational data up to the cloud so that the DERMS can be aware of the secondary level conditions? How might the secondary level operating envelopes coordinate with DERMS-sourced controls/communications? Is the idea that the secondary level would stay more 'decentralized' while primary-level systems would be more centrally coordinated via the DERMS? What happens if there is an aggregator that is connected to residential devices and receives DERMS commands?"
   Response: No response in chat.

5. **11:57 AM — Li, Xian Ming "Cindy"**
   Q: "Based on the slides, is participation in dynamic rates considered part of the dynamic operating envelope? What type of performance/collected data would PG&E need to see from performance on dynamic rates to count that performance and avoid or defer an upgrade?"
   Response (transcript; 02:42:31–02:44:02; Robert Stanford / PG&E): "One distinction between what we call a dynamic operating envelope and a dynamic rate is the dynamic operating envelope is a controlled signal, so there is no price parameter in that at all... we don't currently have any plans to combine... dynamic pricing signals with those dynamic operating envelopes... ... dynamic rates and

deferrals, we haven't currently looked at that, so I don't think we have ... anything to share around whether dynamic rates could be used for deferring."

6. **12:02 PM — Abi Abdallah, Anthony**
   Q: "PG&E says it will scale DERMS on feeders where it provides 'meaningful value'... What is PG&E's operational definition of 'meaningful value' and what threshold qualifies a feeder for scaling? ... What additional criteria...? ... How does PG&E's scaling framework align...? What is PG&E's nearest plan to quantify that meaningful value and share results?"
   Response (transcript; 02:25:16–02:29:29; Robert Stanford / PG&E): PG&E described "meaningful value" as including (a) accelerating "speed to power" / energizing customers sooner, and (b) improving asset utilization and potentially deferring upgrades. They said deferral is "not something we have done yet" but is part of the thesis of a proposed pilot (referencing Rule 29 customers) to identify deferral opportunities. They also noted they publish reports on customers connected to DERMS/Flex Connect (annual or biannual), and suggested value metrics could include "days energized earlier" and "higher asset utilization... incremental megawatt-hours... on the same equipment."

7. **12:04 PM — Marc Monbouquette | Enphase**
   Q (two-part): "1) are the variable operating envelopes (VEOs) calculated locally / at the AMI level, or in the cloud after ingesting AMI data? 2) what is the total latency of device response to a new VOE once calculated...?"
   Response (transcript; 01:46:06–01:47:04; Robert Stanford / PG&E): In the AMI 2.0 "edge connection" description, the meter "in real time will read the load on the home" and (about "every 5 min or so") communicates with peer meters and uses those measurements to "calculate a site limit reflective of what the secondary grid and the customer's panel can support at that point in time," which is then sent to the charger to react to the setpoint; if comms are lost there is a "default safe limit."
   Response (transcript; 01:48:07–01:49:21; Robert Stanford / PG&E): The EV charger adjusts "in near real time" to keep total home load below the limit; transformer limits are "more like a 5 min limit."

8. **12:06 PM — Golson, Cydnie "Cyd"**
   Follow-up / remaining Q: "My question was largely answered... I am still curious... how it would work if an aggregator that received DERMS commands... could also participate in the AMI 2.0-based secondary system operational envelopes... how conflicting messages would be prevented."
   Response: No response in chat.

9. **12:27 PM — Michel Kohanim**
   Q: "is there a document that describes what's missing in OpenADR 2.0/3.0 vs. 2030.5? ..."

Follow-up (Jessica Tellez; 4:53 PM): “Hi Michael, can you send your contact info or reach out to me... so we can respond accordingly.”

10. **2:10 PM — Abi Abdallah, Anthony**
    Q: “SCE’s slide suggests a pathway... ‘bridge-to-wires’... to ‘bridge + permanent flexibility.’ ... how would this transition actually work... eligibility criteria and timing gates... at what point... can a customer elect ‘bridge + permanent’... Any way this can be provided... as a default?”
    Response: See Appendix A - Q&A Transcription and Summary by Session, section C.
11. **2:21 PM — Sky Stanfield**
    Q: “When SDG&E says they have static operational envelopes today, is that referring to the LGP or something else?”
    Response (gwysocki@sdge.com; 2:24 PM): “These are static charging profiles for resources.”
12. **2:29 PM — Woon Jung (CPUC)**
    Q: “Referring to SCE's Slide 6... please specify which secondary/low-voltage capabilities are supported exclusively through ADMS/DERMS and which rely on AMI 2.0.”
    Response: No response in chat.
13. **3:37 PM — Golson, Cydnie “Cyd”**
    Q (for IREC): “How would a flexible connection solution that relies on extending the autonomous volt/var and/or volt/watt functions take into account potential upstream constraints... many small effects leading to a larger effect upstream, such as at a substation”
    Response: No response in chat.
14. **3:48 PM — Robby Simpson**
    Q (for CalCCA): “how is OpenADR more cost effective and scalable than IEEE 2030.5? ...”
    Response: No response in chat.
15. **4:07 PM — Thomas Lee**
    Q (for CalCCA): “Are you envisioning that OpenADR and IEEE 2030.5 would be run concurrently? ... implement and certify to both protocols? ... suggesting a particular version of OpenADR? ... handling interoperability between the different (incompatible) versions of OpenADR?”
    Response: No response in chat.
16. **4:08 PM — Michel Kohanim**
    Q: “Are there any specifications for AMI 2.0?”
    Response: No explicit response in chat.

Appendix C - Workshop Agenda

Agenda

Time	Party/Agenda Item
10:00am-10:45am (45 min)	CPUC (Introduction, Logistics, Background, and Framing)
10:45am-11:30am (45 min)	PG&E – Address topics in ACR Ruling
11:30am-12:00pm (30 min)	Discussion
12:00pm-1:00pm (1hr)	Lunch
1:00pm-1:20pm (20 min)	SCE - Address topics in ACR Ruling
1:20pm-1:50pm (30 min)	SDG&E - Address topics in ACR Ruling
1:50pm – 2:20pm (30 min)	Discussion
2:20pm-2:30pm (10 min)	Break
2:30pm-3:00pm (30 min)	IREC – Topics #1, #2, #3, #4, #5
3:00pm-3:30pm (30 min)	CalCCA – Topics #4, #5, #7, #8
3:30pm-3:45pm (15 min)	VGIC – Topic #8
3:45pm-4:15pm (30 min)	Discussion
4:15pm-4:30pm (15 min)	Closing Remarks

California Public Utilities Commission 5

Appendix D – Workshop Slides

High DER Proceeding Track III All-Party Workshop: Flexible Connections

Rulemaking R.21-06-017

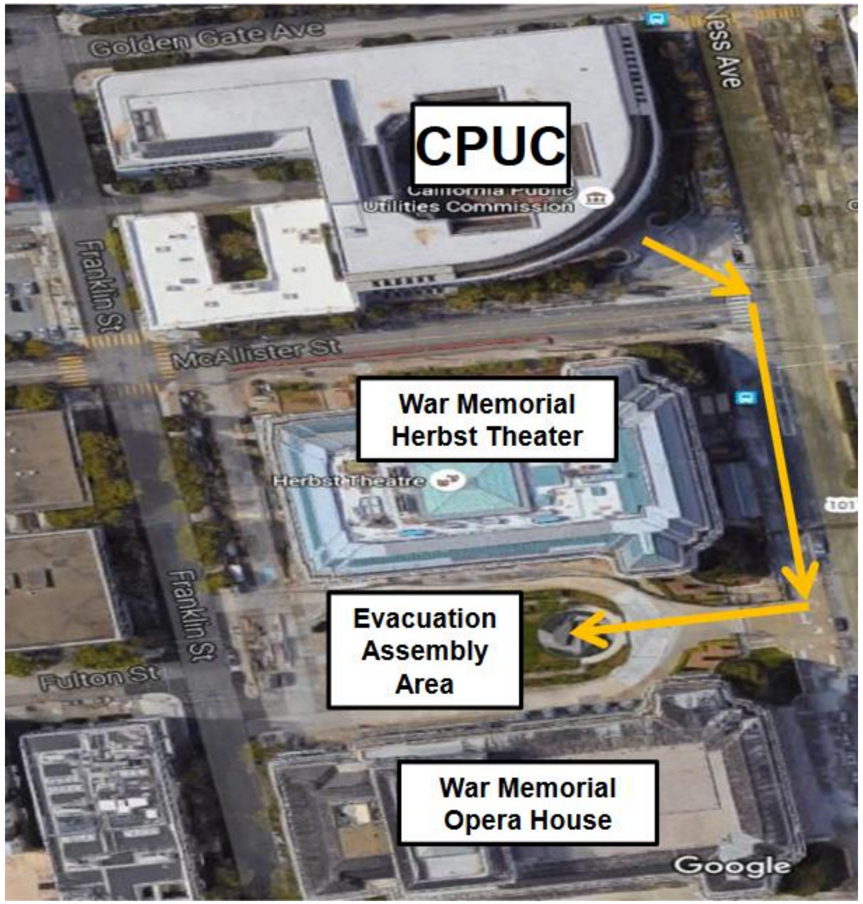
Energy Division

February 20th, 2026

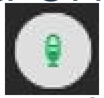
California Public Utilities Commission

Safety & Misc.

- In case of an emergency
  - CPUC Staff will call 911
  - To evacuate, proceed out of 1 of 2 exits to Civic Center Plaza
    - Exit toward Van Ness / McAllister
    - Walk past City Hall
- Bathrooms & water fountain across the Lobby



Ground Rules & Workshop Logistics

- **Ground Rules:**
  - Raise your hand for questions, both in the room and online
  - Identify yourself and your organization before speaking
  - Try not to repeat points that have already been made
  - Stay on topic
  - Please do not interrupt speakers and be respectful of open dialogue
- **Workshop Logistics**:
  - Workshop is being recorded and a link to the recording will be distributed to the service list
  - WebEx and phone participants are muted until called on. Please remember to mute yourself when finished speaking. 
  - Webex participants type questions/comments in the "chat" and they will be read aloud. You may raise your hand to ask the question yourself or follow up on your question. 

Opening Remarks

Commissioner Darcie Houck

Agenda

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3:30pm-3:45pm (15 min)	VGIC – Topic #8
3:45pm-4:15pm (30 min)	Discussion
4:15pm-4:30pm (15 min)	Closing Remarks

Background & Framing

Energy Division Staff

High DER Track III Background

- On **July 2, 2021**, the CPUC issued an Order Instituting Rulemaking (OIR) to Modernize the Electric Grid for a High Distributed Energy Resources (High DER) Future, with three separately scoped tracks.

- The Smart Inverter Operationalization Working Group (SIOWG) was formed under Track 3 Phase 1 of the High DER Proceeding.
  - The SIOWG focused on operational flexibility as the highest priority, defined as the ability of the Distribution System Operators (DSOs) to flexibly optimize the use of existing capacity, allowing more rapid connections of DER and loads, while still maintaining grid safety and reliability.

- On **November 3, 2025**, the Assigned Commissioner's Office issued a ruling that requested additional party comments on recommendations for developing flexible connections between DER customers and the electrical grid where meaningful progress can be made towards better leveraging the electric system to allow for DERs or load to unlock existing capacity.

High DER Track III Flexible Connections Background

The November 3, 2025 ruling requested party comment on:

- Current and projected readiness of technologies needed to support flexible connections, including **Advanced Distributed Management Systems (ADMS)** and **Distributed Energy Resources Management Systems (DERMS)** and related communications technologies, to support and implement flexible connections.
- Implementation of high priority use cases for flexible connections under normal grid operations.
- Implementation and probable use cases for DERs to provide operational flexibility under abnormal grid conditions.
- Potential for flexible connections to be used as a long-term solution, in addition to a bridge to wires solution, without customer compensation.

Workshop Goals and Objectives

1) **What are Primary Use Cases for Flexible Connections?**
   - Applicable to primary grid customer and/or secondary grid customer?
   - Bridging and/or non-bridging solution?

2) **The Distribution Grid Constraint Being Addressed or Problem Being Solved**
   - Clearly articulate what distribution problem is solved and/or benefit created.

3) **Utility, Industry, and Customer Readiness to Implement and Scale the Solution**
   - What technical elements and issues need to be resolved to enable the solution?
   - Can the solution proceed immediately or is a pilot program needed?
   - What is the timeframe to implement the solution (i.e., 2027-2030, 2030 and beyond)?

4) **Costs and Benefits to the Utility Distribution System Operator (DSO) Operator*, Participating Customer(s), and Ratepayers**
   - How cost-effective is the solution and is there a compelling value proposition to all stakeholders that does not depend on compensation?

*Utility DSO refers to the IOU as Distribution System Operator

Discussion Topics Overview

Based on topics outlined in the February 6 ruling, Parties are invited to address the workshop goals of the previous slide while discussing the below topics.

1. ADMS/DERMS capability to offer Variable Operating Envelopes (VOEs) on primary distribution feeders.
2. Using AMI data to enable faster connection for single-phase users.
3. Addressing constraints for secondary customers on shared networks.
4. Utilizing the full range of IEEE 1547 capabilities for customers on shared secondary networks.
5. Appropriate role and definition of aggregator for operating envelopes.
6. Potential modifications to the 2030.5 Communications/CSIP.
7. Aligning dynamic rate structures for existing VOE customers.
8. Customer election of operational envelopes as non-bridging solutions.

February 6, 2026, Assigned Commissioner's and Administrative Law Judge's Ruling Providing All Party Workshop Information and Schedule Modification: *https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M598/K101/598101710.PDF*

Bridging vs. Non-Bridging Solutions

Bridging Solutions: Provides a temporary solution that allows a customer to connect before a needed distribution upgrade is built by operating subject to a limit. It is tied to a planned wires upgrade and converts to full firm service after the wires upgrade is completed. Thus, it "bridges" the time gap between when the customer needs service, and the utility can complete the necessary infrastructure expansion. Facilitates electrification and capacity utilization.

Non-Bridging Solutions: Provides ongoing flexible (non-firm) service, is not tied to a scheduled infrastructure upgrade, is used where a wires solution is not cost-effective or not planned. Enables energization or DER interconnection. May avoid or defer distribution upgrades and uses operational flexibility as a structural grid solution.

Bridging Solution: Load Use Cases

Primary Use Case	***Customer vs. Utility Value Exchange***	***Example***
Temporary import (load) limits to facilitate electrification/ energization	**Utility Value:** Speed to power, unlock existing load capacity, efficient capacity utilization **Customer Value:** Faster connections	Offer **temporary** variable operational envelopes to customers Install load management devices at customer premise Use DERMS/ADMS to effectively manage operational limits

Non-Bridging Solution:

Primary Use Case	***Customer vs. Utility Value Exchange***	***Example***
On-going import (load) limits to facilitate electrification and operational flexibility	**Utility Value:** Unlocks non-firm flexible capacity, defer or avoid future grid upgrades **Customer Value:** Flexibility can lower electric bills, avoid customer equipment, e.g. service panel upsizing, facilitates electrification	Offer **on-going** variable operational envelopes to customers Install load management devices at customer premise Use DERMS/ADMS to effectively manage operational limits

- 'Value' refers to savings from distribution of system-level avoided costs for the grid/utilities (e.g., solutions that defer upgrades) or avoid customer costs (e.g., panel upsizing) Other values include time savings for customers or speed to power for utilities (which brings revenue sooner.)
- Non-Bridging solutions that enable direct financial compensation for customers are not being explored at this time. Non-monetary exchanges may include enabling technologies that unlock savings greater than their cost.

Key Definitions

Primary Distribution Network: A distribution network where the connected customer takes service at the utility's primary distribution feeder (e.g., 4 kV–35 kV range). This is common for large capacity commercial or industrial customers.

- Primary customers are typically **polyphase customers**, but polyphase customers can be connected to both primary and secondary networks

Secondary Distribution Network: A distribution network where connected customers take service at secondary (low) voltage feeders. Secondary customers are typically residential and smaller commercial customers.

- Both **polyphase** and **single-phase customers** can be secondary network customers – polyphase customers are typically commercial or industrially-equipped buildings and single-phase customers typically refer to residential.

Point of Common Coupling: The electrical point where the customer's system connects to the utility grid. It defines the boundary between the customer and utility responsibilities for interconnection requirements, export/import metering, etc.

Note: Definitions are from the November 3rd 2025, Assigned Commissioner's Ruling Seeking Additional Information on DER Enabled Near Term Flexible Connections: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M586/K143/586143237.PDF

Key Definitions

Operating Envelope: The series of operational limits, based on firm and non-firm capacities, within which customers may import and/or export power over a specified time frame (e.g., one day).

- **Temporary Operating Envelope:** Operating Envelope that remains in effect for a specific amount of time (e.g., bridging solutions).
- **Variable Operating Envelope:** Operating Envelope whose collection of operational limits is persistent, based on known firm and non-firm capacity over a predetermined period and modified periodically (e.g., day-ahead). The new collection of limits supersedes the old collection and becomes effective at an agreed upon time.
- **Dynamic Operating Envelope:** Variable Operating Envelope whose operational limits may be updated in near-real time to reflect an updated understanding of additional non-firm capacity.

Flexible Connection: A means of connecting a customer to a utility's distribution system under specific capacity limits that vary over time.

Flexible Service Connection: A Flexible Connection provided for the purpose of serving customer <u>load</u>.

Flexible Generation Connection: A Flexible Connection provided for the purpose of serving customer <u>generation</u>.

Unlocked Capacity: The difference between the capacity provided to a customer under traditional planning methods and the capacity safely enabled by new methods or technologies.

Note: Definitions are from the November 3rd 2025, Assigned Commissioner's Ruling Seeking Additional Information on DER Enabled Near Term Flexible Connections: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M586/K143/586143237.PDF

Topic 1:

ADMS/DERMS Capability to Offer Variable Operating Envelopes (VOEs) on Primary Distribution Feeders

Primary Use Case: Allowing customers connected to **primary distribution feeders** to participate in VOE-based flexible connections for **load and generation,** as either **bridging or non-bridging solutions**

- Define the distribution operational constraint being addressed for both bridging and non-bridging solutions.
- How many existing feeders in IOU service territory can provide VOEs for load and generation?
- How many feeders will be able to support VOEs in near-term rollouts 2027-2030?
- How are overall numbers of customers engaging in VOEs expected to change after offering them to customers?
- Describe the forecast monitoring and telemetry instrumentation needed to enable primary feeders to participate in VOE-based flexible connections
  - Does VOE capability depend on feeder instrumentation?
  - Describe the required costs of feeder instrumentation and rationale for needing them

Topic 2:

Using AMI data to Enable Faster Connections for Single-Phase Users

Opportunity Statement: Can existing AMI data be used to develop operating envelopes to offer to single-phase customers on **secondary networks** as **bridging solutions or non-bridging solutions**?

- Define potential operational constraint to be addressed for both bridging and non-bridging solutions.
- Can AMI data be used to characterize low-voltage grid areas to develop operating envelopes for single-phase customers to participate in flexible connect?
- How cost-effective is the solution and is there a compelling value proposition to all stakeholders that does not depend on compensation?
- How applicable is the Sandia Labs MoHCA methodology (and alternative approaches) for IOUs, and what are its key limitations?

Topic 3:

Addressing Constraints For Secondary Customers on Shared Networks

Problem Statement: Customers connected to shared secondary networks also share secondary equipment (e.g., service transformers) with neighboring customers, sometimes delaying requests to connect and driving up utility-side infrastructure and customer-side equipment costs.

Opportunity: Can the use of DER aggregator controls (inverter, smart panel, meter collar, gateway limits) be a **bridging and/or non-bridging solution** for customers on **shared secondary networks**?

- Identify current platforms technically capable of secondary feeder level aggregator controls
- What costs are associated with aggregator access to site equipment?
- What are the addressable benefits that could be unlocked:
  - Utility Side: Avoided or deferred transformers and secondary infrastructure upgrades.
  - Customer Side: Avoided service panel upsizing costs.
- How soon can this use case be deployed at scale?

Topic 4:

Appropriateness of Requiring Extended Volt/VAR and Volt/Watt Curves for Generating Assets Using Operating Envelopes on Shared Secondary Equipment

Problem Statement: Tariff Rule 21 specifies a set of default volt/VAR and volt/watt curves for generating assets, allowing exception to these curves by mutual agreement between the IOU and customer. IEEE 1547 specifies a wider range of operation than is enabled by the default curves currently codified in Rule 21.

Opportunity: For customers with **generating** assets on **shared secondary networks,** should inverters be allowed to extend real and reactive power operations beyond the default curves outlined in Rule 21?

- Under what circumstances and when would it be appropriate to require generation customers to utilize the full set of IEEE 1547 capabilities for these functions?
- Provide examples of potential benefits.
- How would the utility DSO determine the need for alternative volt/VAR and volt/watt curves and how would the settings be changed/updated?
- Would any additional functions (e.g., rate of change of frequency, etc.) be appropriate.

Topic 5:

Role and Definition of Aggregator for Operating Envelopes

Problem Statement: Clarify the role, scope, interoperability standards, and cost implications of aggregators to enable scalable flexible connections for primary and secondary system constraints without limiting program participation or innovation.

- **Definition/Role Differentiation**: Should the Commission distinguish between (1) technical service providers that enable telemetry and dispatch access, and (2) aggregators that enroll and manage devices for program participation? If so, what responsibilities attach to each role?
- **Protocol Neutrality/Interoperability Requirements:** Should "aggregator" be defined in a communications-protocol neutral manner (e.g., not limited to IEEE 2030.5 cloud services), consistent with Rule 21 allowances for mutually agreed protocols? If so, what minimum interoperability requirements are necessary to ensure operating envelope compliance?
- **Primary vs. Secondary Constraints:** Do secondary (shared transformer/network) use cases require stricter technical or certification standards than primary (feeder-level) use cases?
- **Bridging vs. Non-Bridging Solution:** Should aggregator-mediated compliance be used in both cases?
- **Accountability & Enforcement:** Who is responsible if envelope limits are exceeded or communications fail? What certification, auditing, or performance requirements are necessary to ensure reliable compliance?
- **Cost & Access Barriers:** Do manufacturer or platform access fees (e.g., proprietary fees) reduce aggregator participation or the cost-effectiveness of operating envelops? If so, what guardrails are needed to address theses access constraints?

Topic 6:

Potential Modifications to the 2030.5 Communications/ Common Smart Inverter Protocol (CSIP)

Problem Statement: To discuss whether existing or planned utility communications infrastructure can support VOEs and the appropriateness of standardizing on a single protocol for communicating DERMS information.

- Could existing or planned IEEE 2030.5/CSIP infrastructure at the utilities be used to communicate to devices or entities that primarily use a different protocol?
- Does CSIP[1] have all the functions needed to implement VOEs? If not, does IEEE 2030.5 (the base standard) contain all the needed functions?
- Can CSIP currently support the commands used by other protocols such as OpenADR?
- Is intermediate translation via aggregators or onsite gateways sufficient to bridge IEEE 2030.5/CSIP signaling and DER receipt of information?
- Is it appropriate to standardize on a single communications protocol (e.g. IEEE 2030.5/CSIP) for communicating DERMS information?

[1] CSIP (Common Smart Inverter Profile) defines the standardized way that CPUC-jurisdictional utilities communicate with DERs over the internet using the IEEE 2030.5 protocol, whether directly or indirectly through aggregators or onsite gateways.

Topic 7:

Aligning Dynamic Rate Structures for Existing VOE Customers

Discussion Question: How will participating in dynamic rate pilots or future dynamic rates impact customers receiving variable operating envelopes?

- **Existing dynamic rate pilots (PG&E and SCE) are shadow-billed**
  - Dynamic bills are computed in parallel and customer continues to pay TOU bill
  - If annual dynamic bill is less than the annual TOU bill, customer receives a bill credit
- **Customers who are enrolled into the shadow-billed pilots face no penalty if they do not respond to the prices**.
- **Customers who are "defaulted" onto rates retain the ability to switch to other eligible rates**
- **Does the design of dynamic price pilots in CA provide complimentary benefits for VOE customers?**
  - Dynamic prices are lower than TOU prices for most of the year AND high-prices are concentrated into fewer hours than equivalent TOU rates
  - Dynamic distribution prices are based on primary network congestion (local feeder/substation) – Which can be complementary to VOE
  - Automation capabilities needed to respond to VOEs provide customers a natural advantage in shifting load in response to dynamic prices

Topic 8:

Customer Election of Operational Envelopes as Non-Bridging Solutions

Discussion Question: Under what circumstances and use cases should customers have the option to adopt operational envelopes as a non-bridging solution?

- What are the conditions that would justify customers using operational envelopes as a non-bridging solution?
  - Where a wires solution is not cost-effective or not planned?
  - To enable electrification or DER interconnection?
  - To avoid or defer distribution upgrades?
  - To uses operational flexibility as a structural grid solution?

PG&E's High DER Track 3 Workshop Presentation

February 20, 2026

Primary Distribution

High DER Track 3 Background

- The overall objective of the High DER proceeding (R.21-06-017) is to prepare and operate the grid for high electrification through proactive planning while meeting customer needs, accommodating increased load, and maintaining affordable rates.
- The proceeding is broken up into three tracks with multiple phases within each track:
    1. Distribution Planning and Execution Process and Data Improvements
    2. Distribution System Operational Needs and System Operator Needs
    3. Smart Inverter Operationalization and Grid Modernization (DERMS, Load Management, etc.)
- In Track 3, a series of Rulings were issued in 2025 requesting parties' input on areas where meaningful progress can be made towards better leveraging the electric system to allow for DERs or load to unlock existing capacity:
    - DERMS/ADMS to enable variable operating envelopes addressing primary infrastructure constraints
    - Tools for characterizing low voltage networks and generating operating envelopes via AMI
    - Aggregator mediated operating envelopes for shared secondary constraints and defining aggregators
    - Communications protocols
    - Dynamic rate alignment
    - Non-bridging solutions

DERMS/ADMS to enable variable operating envelopes

Overview

- PG&E DERMS focuses on managing primary distribution infrastructure constraints today
- PG&E's DERMS enables forecasting, dispatch, and M&V of variable operating envelopes and has been used in production for 6 sites since October 2024
- Dynamic Operation Envelopes are dispatched to technology providers via the standard protocol IEEE 2030.5, and are done on a day-ahead hour-interval basis with real-time updates sent by exception if needed
- Local fail-safes are required in the event of communications loss and other emergent conditions or system failures

Flexible Service Connection

24hr ahead DER customer import limits

Microsoft Azure

EcoStruxure DERMS

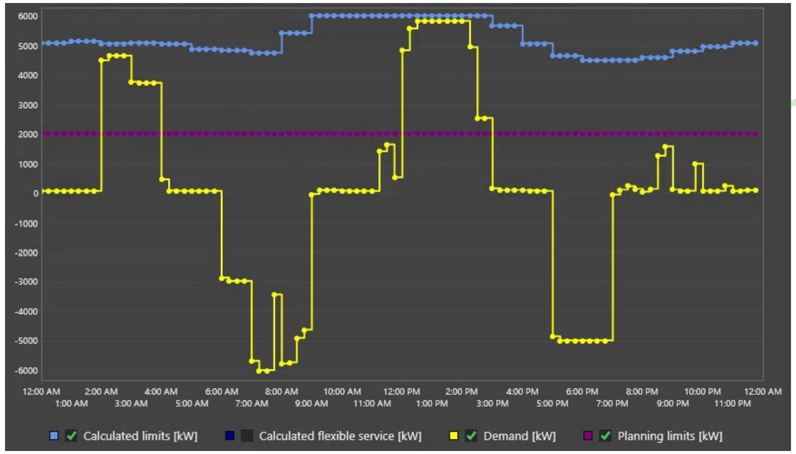
Customer & DER Data

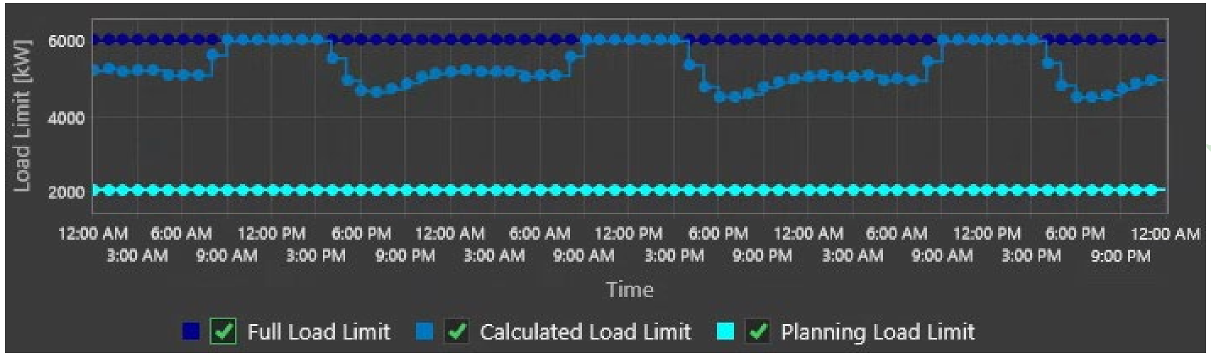
DER Contract Info

As-Operated Network

Historical Data

Weather Data





Measurement and verification for benefits and compliance

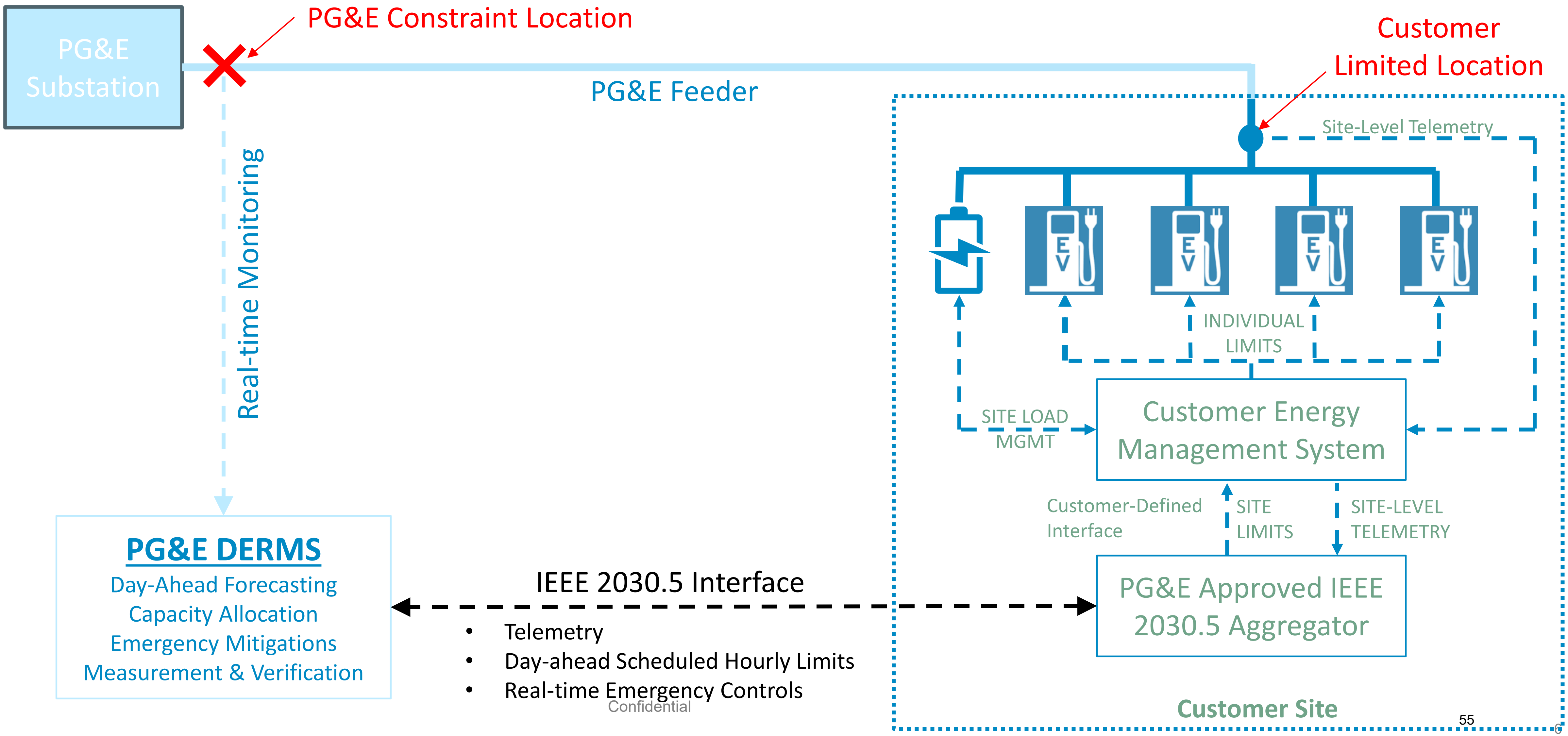
Controls

Telemetry

Detect capacity constraints and determine dynamic site limits within DER contract parameters

Unlocks more capacity on the grid, increases utilization, and allows more customers to connect sooner

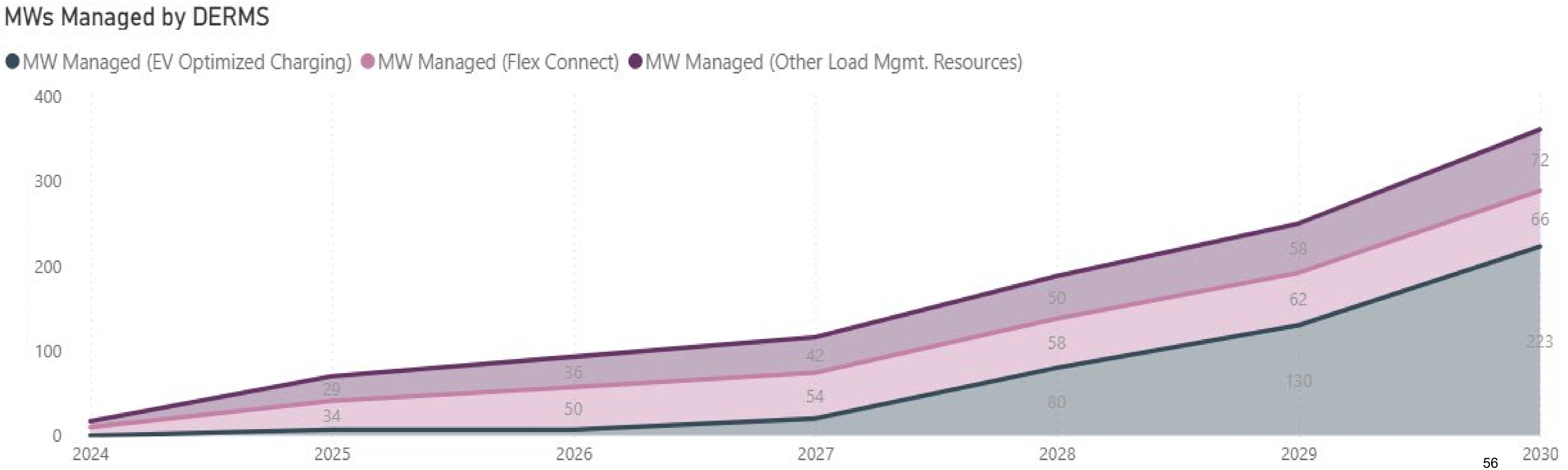
Flexible Service Connection Pilot – Illustrative Site Configuration



- Telemetry
- Day-ahead Scheduled Hourly Limits
- Real-time Emergency Controls

Variable Operating Envelopes: Scaling

- As of February 2026, PG&E has 3 live BESS sites being controlled via Grid DERMS including 1 site with a variable generation operating envelope control. In addition to the 3 BESS sites, PG&E also currently controls 2 EV charging sites via load-side variable operating envelopes

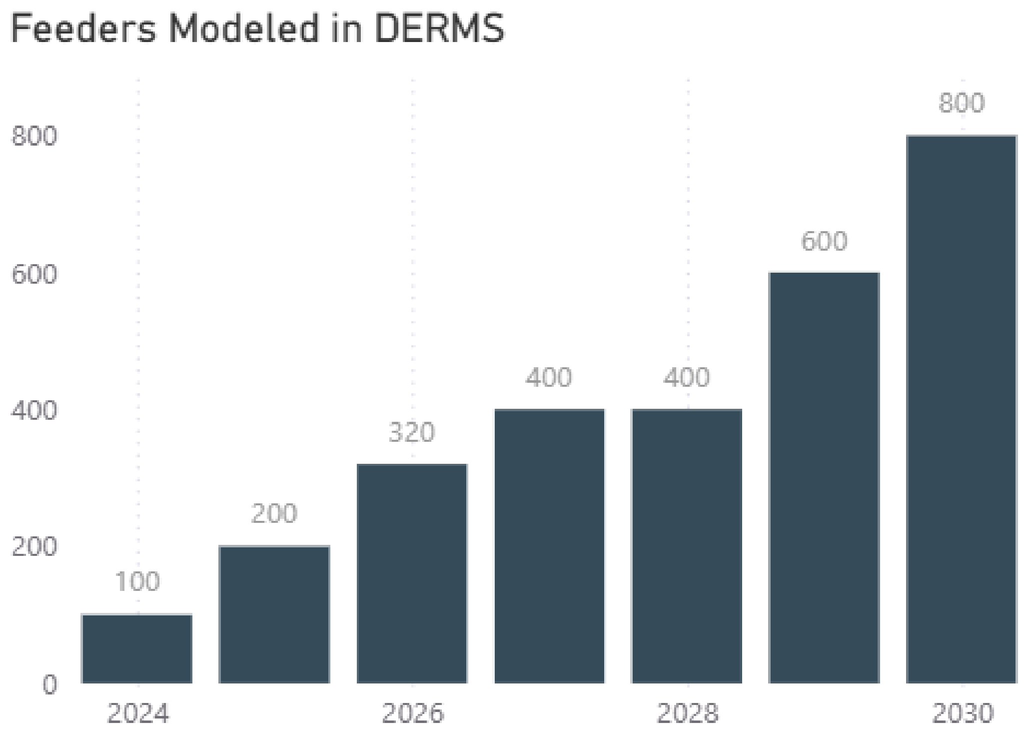


Variable Operating Envelopes: Scaling

Key Consideration
DERMS costs (setup, O&M) scale with the amount of the network that is modeled

Scaling Responsibly
PG&E plans to scale DERMS across feeders where DERMS provides meaningful value

- Specific C+I DERMS-connected customers
- High DER penetration feeders



Note: PG&E's entire network is ~3200 feeders

Flex Connect Customer Insights

Customers value Flex Connect primarily for:

1) Timely access to available capacity in the site design phase, enabling more informed and economically sound decisions
2) The Flex Connect 288 load analysis report with additional capacity expected during certain hours; the heat map format has been well received by customers

Challenges for program scaling:

1) Customers and vendors are required to do up-front investment to incorporate support for variable operating envelopes into their existing control equipment. 3 vendors have now completed interoperability certification, with 5+ more scheduled to complete in 2026.
2) Initial DERMS implementation does not yet support **line-section constraints** and **multiple sites on the same constraint** (on pace for delivery by end of 2026)
3) Slow adoption of the IEEE 2030.5 communication protocol is driven by uncertainty stemming from varying DERMS development stages, differing utility priorities in California and across the US, and differing use cases, specifically load management versus inverter-based DER control

Communication Protocols (IEEE 2030.5) How it works for PG&E's Flex Connect today

Flex Connect is the first application where DERMS must communicate an operating limit envelope to customers, and PG&E's selection of IEEE 2030.5/CSIP is driven by the specific technical requirements of this use case based on the following rationale:

1) Fail-safe operation for large C&I customers (1–20 MW).
   - Flex Connect targets high-capacity sites where grid operators require a dependable fallback fail-safe mode. IEEE 2030.5/CSIP supports the ability to revert to the static limit in the Load Limit Letter during communication loss or emergency conditions, ensuring system safety and reliability.
2) Integrated cybersecurity with certificate-based authentication.
   - IEEE 2030.5 includes a built-in public key infrastructure that enables device-level authentication and secure communication, which is an essential requirement for large commercial assets participating directly in grid operations.
3) Day-ahead scheduling capability.
   - Flex Connect requires the ability to deliver 24-hour operating schedules so that customer facilities and BESS operators can plan operations and/or adjust wholesale market bidding strategies accordingly. IEEE 2030.5 natively supports structured schedules and forecast publication.
4) Already an existing required protocol, for low-cost customer telemetry (Rule 21)
   - Aligning on a reuasable standard protocol provides necessary stability to vendors while also allowing for the utility to stack more value over time as new use cases are able to reuse existing technology investments (i.e. DERMS, 2030.5 protocol)

Communication Protocols (Modifications to 2030.5)- forward-looking improvements to enable program scaling

Strategy #1: Reduce onboarding timelines and fewer vendor integration issues via supporting standardization (with SunSpec Alliance and IEEE 2030.5 working group):

- Incorporate PG&E's interoperability testing plans into the standard CSIP-CA certification test plan, reducing redundant vendor testing.
- Publish aligned profile guidance and test plans so vendors implement consistent operating-limit behavior statewide.
- Create a single, statewide certification pathway for import capacity operating-limit use cases.

Strategy #2: Reduce implementation complexity by creating a simpler IEEE 2030.5 profile than what is required with CSIP, focused only on minimum requirements for variable flexible service connections

Secondary Distribution & Panel Constraints

Why is a panel or secondary/service upgrade needed?

Customer	AHJ	Utility
No space	Unpermitted work in panel	Within gas clearance
	Work not up to code	Fail Rule 2 voltage
	Failed load calculation **(site limit)**	Overload service wire **(site limit)**
	Failed 120% backfeed rule *(Rule 21 export only)*	Overload secondary wire **(grid limit)**
		Overload secondary transformer **(grid limit)**

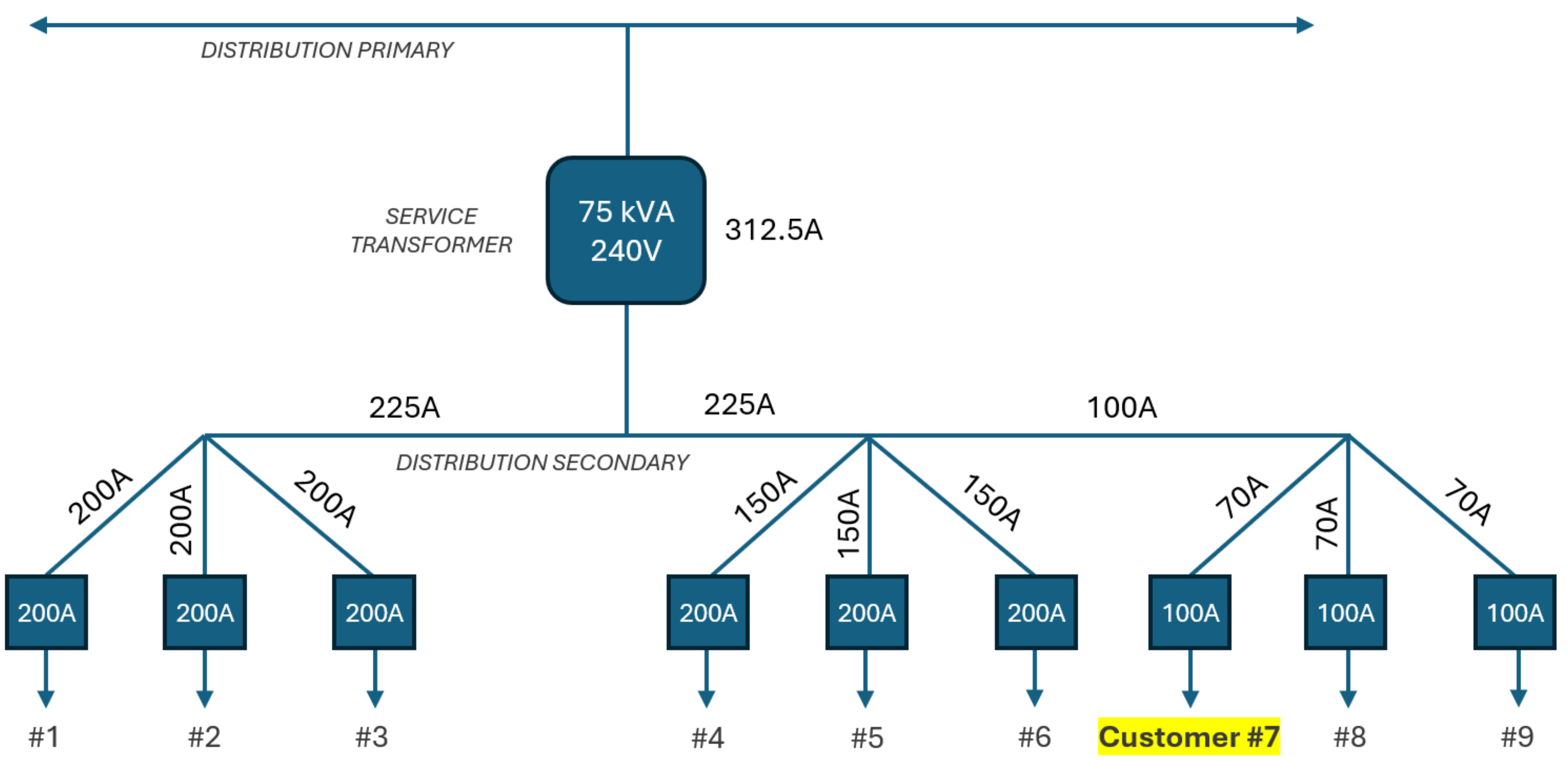
How customers currently solve these problems

$ → *Wire it up, don't tell anyone*

$$ → *Implement a panel only solution*

$$$ → *Coordinate with SP&D, potential upgrade*

What is required to avoid or defer an upgrade?



For Customer #7 the following constraints apply:

1. Limit 312.5A at the Service Transformer
2. Limit 225A at the Secondary
3. Limit 100A at the Secondary
4. Limit 70A at the Service Wire
5. Limit 100A at the Main Breaker
6. Limit 0.95pu voltage at every Meter
7. Limit 0.95pu voltage at the Meter

Additionally, multiple external constraints may be desired in the future:

8. Limit amperage to the primary feeder
9. Limit amperage to the substation

Deferring a secondary upgrade requires management of hyper local near real-time constraints

How is PG&E working towards enabling secondary deferrals?

PG&E has two projects which are developing the capability to defer secondary & service transformer upgrades:

EPIC 4.02 – AMI 2.0 Edge Management (EVs & Any Electrification Load via Smart Panel)

Purpose: Connect customers immediately without upgrades

Method:
1. AMI 2.0 meter in real-time monitors load and voltage on the secondary
2. An operating envelope is calculated on the meter and sent locally
3. The EV charger or smart panel adjusts its output to the available capacity

EPIC 4.04 – Cloud Aggregated Management (Electric Vehicles)

Purpose: Defer secondary transformer replacements

Method:
1. An EV is enrolled in a cloud aggregation
2. A service transformer forecast is generated
3. The vehicle charging is rescheduled based on the transformer limits while staying within the off-peak window

		AMI 2.0	Cloud Mgmt
Customer Value	Panel upgrade avoidance	✓	✗
	Service upgrade avoidance	✓	✗
Grid Deferral Value	Service wire	✓	✗
	Secondary conductor	✓	✗
	Service transformer	✓	✓
Solution Capabilities	Load management	✓	✓
	Voltage management	✓	✗
	Software only	✗	✓

Both projects will have public reports with research, findings, and next steps published at completion.

EPIC 4.02 – ChargeBoost & PanelBoost deep dive

Customer Experience

Today

- ~50% of customers have 100A panels which need immediate upgrade to 200A to serve Level 2 EV home charging
- Many of these customers will trigger service upgrades which can vary in cost from $3,000 to $50,000/site with 2-to-12 month durations
- Customers either don't buy or return an EV, charge on Level 1 outlets, or perform unpermitted work causing transformer failures

Future

- Customer enrolls in ChargeBoost or PanelBoost on pge.com
- A new meter is installed on the premise while the EV charger or smart panel is being installed
- The meter and new load are coordinated with the grid without a panel or service upgrade

Coordinated electrification load can defer infrastructure replacements

Month -->	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	25.4	21.8	23.8	19.0	21.4	25.5	25.1	32.0	31.7	17.9	26.9	27.0
1	25.3	21.3	19.9	27.4	25.2	29.4	28.1	31.1	39.1	18.9	24.6	23.3
2	26.2	27.6	25.4	27.8	25.3	30.0	32.9	36.3	36.7	22.5	28.8	22.4
3	26.2	24.7	22.7	25.6	22.4	24.4	30.3	33.5	27.8	30.9	22.5	22.0
4	26.7	20.9	22.2	22.2	14.5	21.4	32.9	23.3	32.7	24.0	30.9	33.5
5	28.7	26.7	26.4	22.5	11.6	21.9	30.1	31.3	39.0	31.5	36.6	33.8
6	28.1	28.5	28.3	23.7	11.5	28.4	33.3	29.8	31.8	29.0	30.7	33.7
7	27.8	25.4	27.4	15.4	14.1	22.3	27.0	18.5	16.4	20.3	23.3	27.8
8	23.5	34.0	28.1	17.3	16.0	15.1	20.5	17.1	17.2	19.9	21.4	33.6
9	30.2	23.9	21.2	20.2	17.7	18.4	18.9	20.4	21.3	18.3	20.8	23.9
10	28.3	25.0	23.5	22.9	23.7	17.5	19.0	24.9	28.6	22.2	24.7	25.4
11	25.3	24.5	29.4	24.9	22.9	23.9	20.5	29.2	33.1	23.6	24.5	26.8
12	25.6	23.9	25.4	27.1	29.1	26.3	23.9	37.4	32.1	29.5	24.6	28.6
13	26.5	24.0	24.4	25.3	37.0	31.7	25.0	38.7	41.3	29.3	28.1	29.7
14	25.7	28.6	27.2	28.5	39.2	36.3	29.6	46.4	54.2	26.8	27.8	26.7
15	27.0	31.1	24.9	32.8	41.6	37.6	33.0	52.2	58.4	33.1	22.3	28.3
16	27.4	30.3	25.5	22.9	41.9	51.9	38.5	53.6	58.8	40.2	22.9	24.6
17	29.0	28.6	29.3	22.1	44.4	49.9	34.1	54.3	60.5	39.0	25.0	28.6
18	34.5	29.6	30.2	23.6	46.1	52.6	36.9	54.4	60.0	40.8	25.5	31.1
19	29.7	28.6	26.4	23.6	43.1	49.7	37.1	55.2	54.0	31.7	27.5	32.2
20	29.0	27.2	28.5	24.7	41.8	45.2	30.7	47.2	51.4	31.0	26.6	29.7
21	30.2	30.5	27.0	28.0	45.6	38.3	26.3	45.2	43.2	30.6	27.5	34.4
22	30.6	28.4	29.7	25.9	39.4	36.8	27.3	40.2	39.1	25.3	28.1	33.2
23	30.5	28.6	24.5	24.4	26.5	36.6	25.2	34.8	34.3	26.8	29.3	27.4
Nightly surplus	307	310	316	325	330	318	313	308	316	325	313	301
Commutes	**26.1**	**26.4**	**26.9**	**27.7**	**28.1**	**27.0**	**26.7**	**26.2**	**26.9**	**27.6**	**26.6**	**25.6**

- Transformer fails >60 kVA in Union City before adding EVs
- Nightly capacity surplus enough for 25.6 additional commutes
- Realistic opportunity will *balance load control and upgrades*

Enabling 70% load growth requires delivering down to the customer.

EPIC 4.02 – Options for any type of load

ChargeBoost

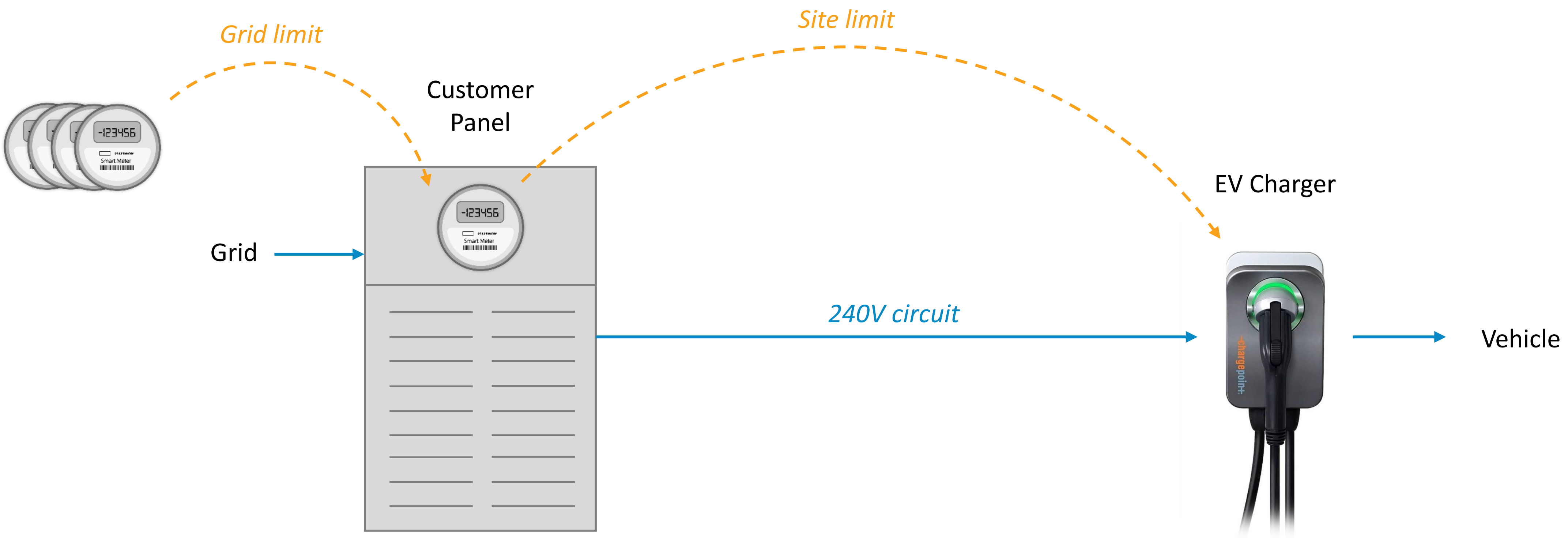
PanelBoost

EV CHARGING
Lowest cost EV connection without needing an upgrade

FULL ELECTRIFICATION
Connect anything without needing an upgrade

Standardized connections via OCPP 1.6J and Matter

EPIC 4.02 – Function



Meter

1. Store config from head end
2. Read site load
3. Read transformer load
4. Calculate site limit
5. Post site limit

Communications

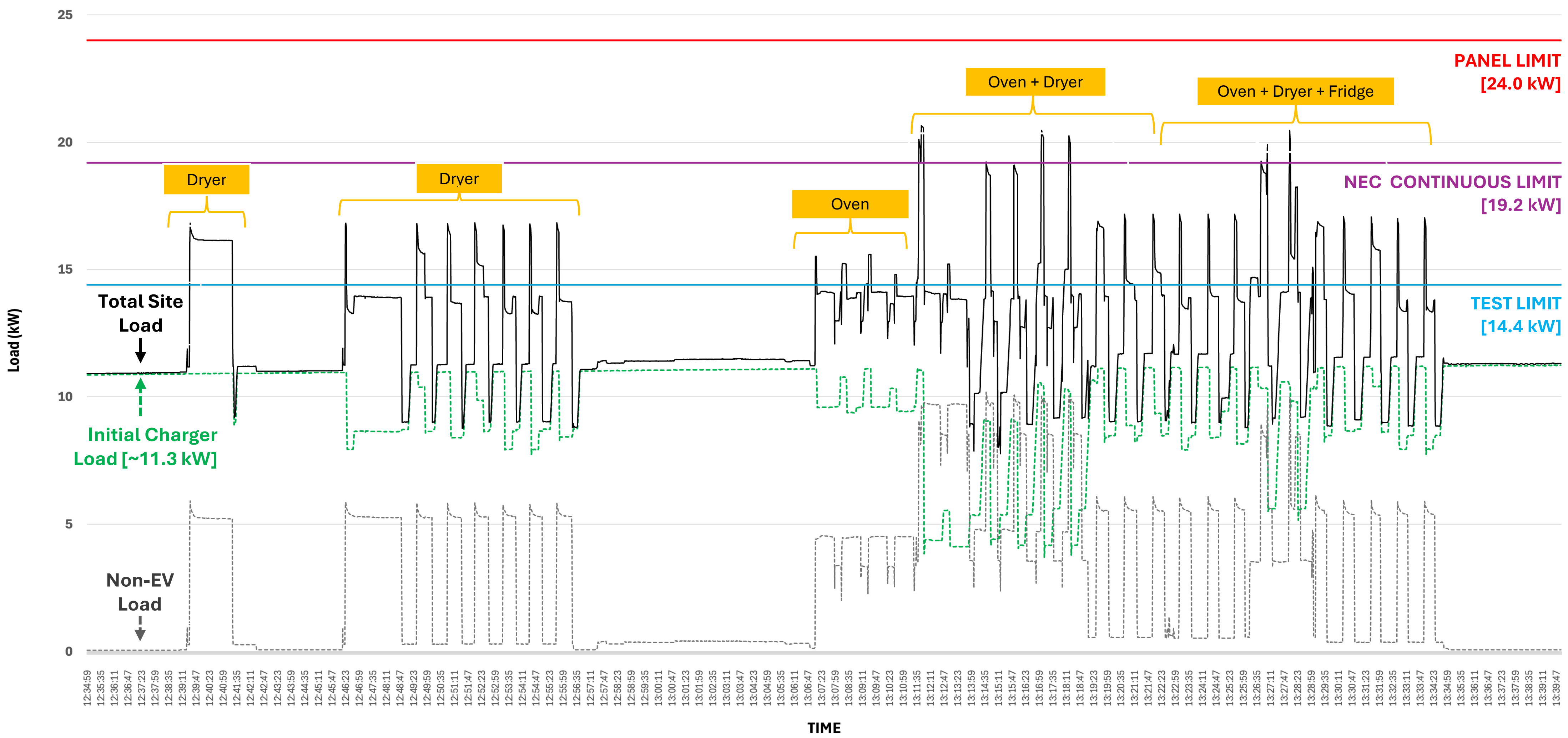
1. Establish secure link
2. Transfer site limit

Charger

1. Poll site limit
2. Adjust output to under limit
3. Default to safe load if comms lost

Note: Charger for illustrative purposes only

EPIC 4.02 – Real world results (panel level)



Real-time operating envelopes enable connections at the customer premise

Exploration of Existing AMI for Secondary Distribution Operating Envelopes (Section 5)

Concept: Use of existing AMI low voltage data for generating operating envelopes at the secondary level

Benefits:

- Existing AMI data (AMI 1.0) is available today across almost all of the grid

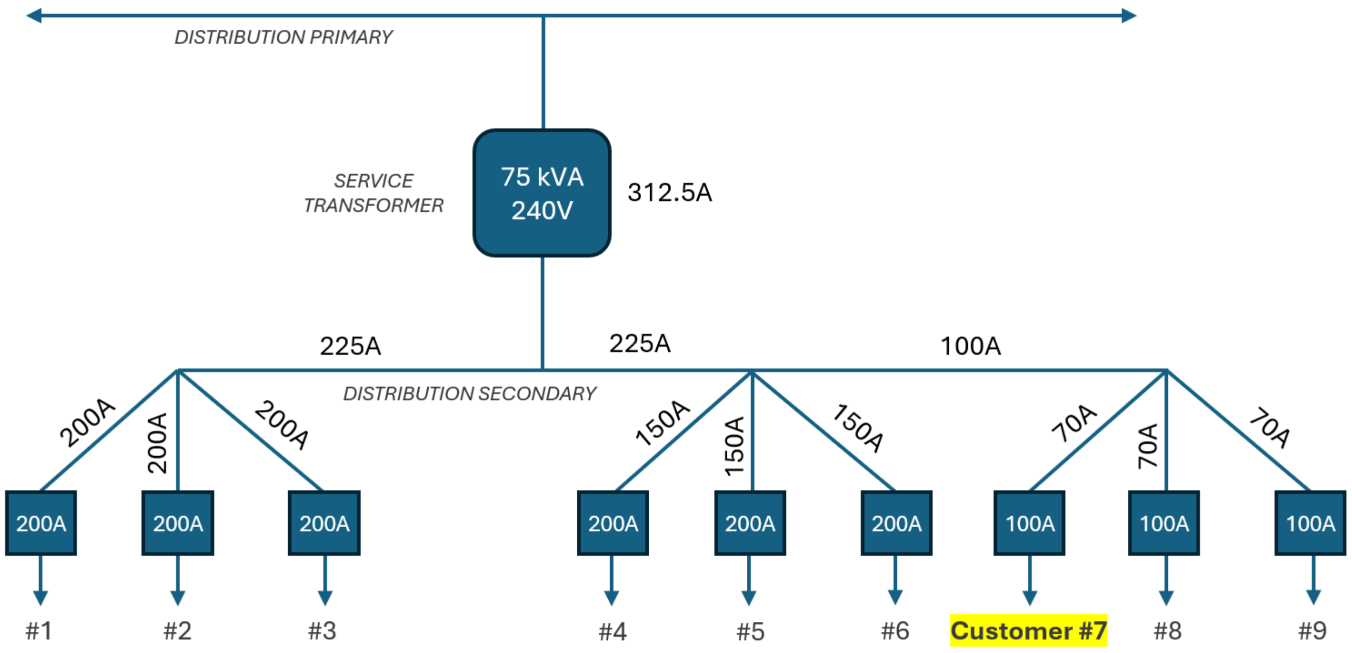
Challenges:

- Lack of load diversity on the secondary network
- Lack of real-time or near-real time backhaul of **load and voltage data**

Feasibility:

- Potentially feasible but <u>*unproven and with significant challenges*</u>:
  - Without near-real time measurements, forecasting is the only other option for generation of an operating envelope
  - Forecasting of load is challenged significantly by a lack of load diversity at the transformer and even more so at the shared secondary wire
  - Forecasting of voltage for the purposes of power quality is further challenged down to the service point
- <u>Practical example:</u> 20 customers on a 50 kVA transformer 6 of them with 10 kW EVSEs and 20 kW of base load.
- Calculation of an operating envelope by forecast would require unreliable assumptions around how many of these customers are charging that specific day/time and introduces the risk of overloading the transformer (asset health/safety issue), or the overload of a conductor (safety issue), or the creation of a low voltage event (Rule 2 power quality issue).

Exploration of Existing AMI for Secondary Distribution Operating Envelopes (Section 5)



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Additionally, multiple external constraints may be desired in the future:

8. Limit amperage to the primary feeder
9. Limit amperage to the substation

Above: A simplified and illustrative example of the real-time constraints on the secondary system.

Recommendations:

1. Continue the EPIC 4.02 (AMI 2.0) and 4.04 (Cloud Aggregator) projects which are exploring the potential for secondary operating envelopes. Both projects will share public reports at conclusion which will confirm feasibility of these solutions.
2. Deployment of an AMI 2.0 system in some capacity is likely foundational to solving this challenge (due to the ability to calculate real-time edge constraints) regardless of controls via edge devices or a cloud system.
3. It is premature to standardize a method before additional proof points.

Exploration of Aggregator Enabled Operating Envelopes' Use for Shared Secondary Constraints (Section 6)

Concept: Use of aggregators for generating operating envelopes at the secondary level (secondary distribution)

Benefits:

- Devices which are already in aggregations, or could be cost-effectively recruited, could contribute to secondary capacity

Challenges:

- The challenges from the previous Section 5 response; plus
- Cost for device connectivity, response time, and/or availability and reliability of load management

Feasibility:

- Potentially feasible but *unproven and with significant challenges*:
  - The prior Section 5 response must be feasible; and there is,
  - Expanded uncertainty around cost for device compensation vs. the upgrade, the reliability/availability of the load, and whether a sufficient factor of safety can exist that also creates a meaningful amount of capacity while costing less than a secondary upgrade

Recommendation:

1. Continue the EPIC 4.04 project which is explicitly evaluating the use of **aggregator** capabilities for the purpose of deferring secondary grid upgrades and share the public reports at conclusion.
2. It is premature to standardize a method before additional proof points.

Alignment Points

Defining Aggregators

- PG&E believes it would be helpful to differentiate between an entity that provides technical access to multiple end-devices for the purposes of telemetry and dispatch (e.g. "technical service provider") versus an entity whose primary function is to aggregate devices for the purpose of enrollment and participation in programs (e.g. "aggregator")

Dynamic Rate Alignment

- **Alignment:** PG&E recognizes that customers who have the capability to flex load in response to variable operating envelopes may also be good candidates for responding to dynamic prices.
- **Recommendation #1 - Dynamic Pricing Should Remain Optional:**
  - Customers' decisions about when and how to engage with dynamic rates should remain an active optional choice because:
    - Responding to dynamic price signals may require more dynamic load response capability beyond what is needed to respond to capacity-based operating envelopes.
    - Along with more dynamic load response capability, benefitting from dynamic pricing requires customers to leverage algorithms that optimize price arbitrage and consider customer-specific opportunity costs of altering usage patterns.
  - Customers participating in load response to meet capacity-based operating envelopes can be provided information about dynamic pricing rates, but they should not be required to take service on, nor should they be defaulted to, a dynamic rate.
- **Recommendation #2 - No Separate Treatment for Shadow Biling and Customer Protections**
  - Provisions related to shadow billing and customer protections that are applicable to any customers taking service on a dynamic rate should apply.

Non-Bridging Solutions

- **Possible direction for a pilot to increase scale of PG&E Flex Connect sites:**
  - Use load flexibility to manage near-term overloads while allowing capacity projects to be planned and delivered incrementally, aligned with long-term growth, sustained asset utilization and the best possible ratepayer outcomes
  - Focus on EV charging sites (Rule 29 sites) since those site may be able to accept flexible service connections without meaningful negative impact on end-customer charging
  - Goal is to demonstrate meaningful changes to increasing speed-to-power, adding flexibility to capacity upgrade timelines, without significant impact to end-customer EV charging experience

Appendix

Together, Building
a Better California

High DER Track 3 Stakeholder Workshop

SCE Presentation

February 20, 2026

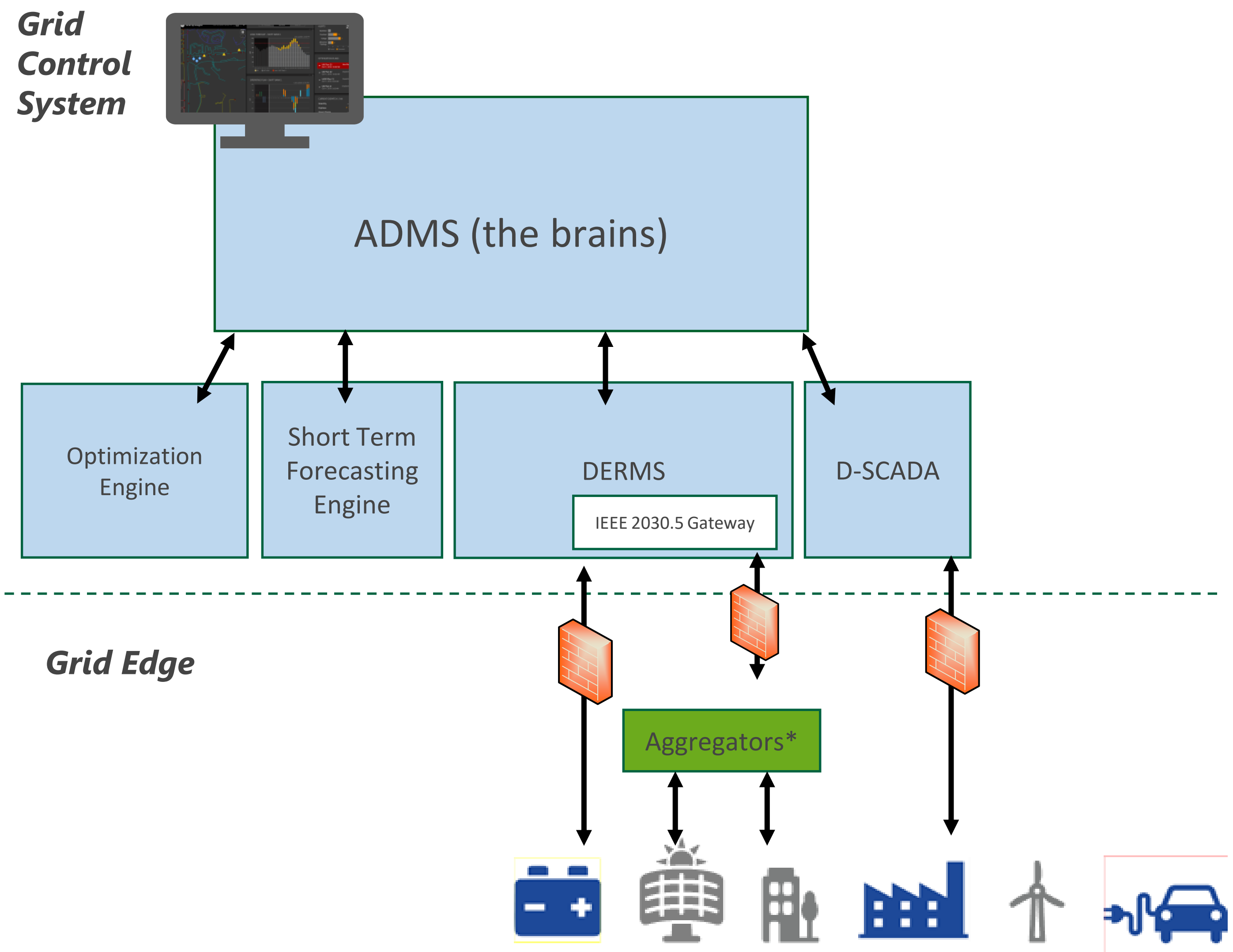
Summary

Alignment	• SCE supports the overarching objectives of Track 3, including improving DER operational integration, enabling flexible interconnection, and modernizing grid capabilities to support increasing DER penetration.
Approach	• Focus on scalable, technically feasible solutions that leverage existing and planned capabilities (e.g., DERMS/ADMS, automation). • Advance DER functionality in a manner that is cost-effective for customers, operationally reliable, and aligned with real-world deployment readiness.
Objective	• Collaboratively refine where, when, and how Track 3 tools and requirements should be applied to maximize grid value while supporting orderly implementation.

Agenda

- SCE's Grid Management System (GMS) Implementation Roadmap
- Key DERMS Capabilities Related to Grid Orchestration
- Review of Eight Focus Areas Identified by CPUC Ruling

SCE's Grid Management System Enables Communication to Customers and Aggregators



- GMS is a system of systems that provides integrated grid management functions and one pane of glass for distribution operations
- Shift towards model driven operations will enable greater utilization of the electric grid while enabling much needed operational flexibility
  - Allow SCE to run the grid closer to operating limits
  - New model driven analytics that enable greater grid flexibility and shift towards active grid management

*See proposed definition of Aggregators on Slide 7

Initial GMS Capabilities Provide a Foundation for Expanded Use Cases

Phase 1 ADMS		***Phase 2 DERMS***	***Phase 3 Adv. ADMS & DERMS***	***Phase 4 Grid Platform***
Release 0.5 (Complete) ***D-SCADA upgrade*** **May 2021**	***Release 1 (Testing)*** ***Adv. DMS, OMS, & DERMS*** **2023-2026**	***Development*** **2026-2027**	***Plan*** **2027-2028**	***Plan*** **2028+**
Back-office platform that is virtualized, scalable and highly resilient to support ADMS and DERMS	Advanced grid mgmt. functions, including automated fault location, isolation and service restoration (FLISR), electronic switching, base DER mgmt., and mobile grid operations	PSPS automation DER short-term forecasting and optimization, secure field devices, and energized wire down event detection	Expand mobile grid operations, outage metrics, operator training systems, microgrid mgmt., and storm analytics capabilities	Expand Load management, adaptive protection, Power quality management and Substation Device Management capabilities

D-SCADA Functionality

Infrastructure upgrade to support:
- D-SCADA Operations
- Red Flag / Load Shed
- Distribution Volt Var Control
- Tie Device Restoration Logic

OMS Functionality
- Replace and Enhance OMS Functions
- Fully Integrated Electronic Switching Management
- Deploy Mobile ADMS field functions

DMS Functionality
- Deploy Advance Distribution Network Analysis Functions
- Deploy Assisted Switching (Fault Location Isolation & Service Restoration, Protection Validation)
- Enhanced Volt Var Control

Base DERMS
- DER & Programs enrollment
- IEEE 2030.5 Gateway for DER telemetry, dispatch and Control via aggregators, SCE approved Cloud Service Providers & Edge Gateways
- SCADA enabled DER telemetry, dispatch and control
- Remote DER Lockout/Disconnect

DERMS Functions
- Short-term Forecasting (Load & Generation)
- Optimization Engine
- Constraint Management
- Dynamic Operating Envelopes
- Flexible Interconnections

ADMS Functions
- Next generation integrated ADMS and DERMS
- Wildfire/PSPS- GMS Integration
- MADEC (automatic wire down detection & isolation)
- Device Management

Advanced ADMS Functions
- Storm Analytics
- Mobile Grid Operations expansion
- Outage metrics expansion
- Microgrid Management

Advanced DERMS Functions
- Operator Training expansion (high DER)
- DER response to weather modeling and islanding

Grid Platform Functions
- Adv. Load management
- Substation device management
- Power Quality platform
- Adaptive Protection

DERMS Capabilities

*Current roadmap & schedule apply to the Distribution system only, and not Sub-transmission or Transmission voltage levels

SCE Supports Implementation of Four CPUC-Identified Topics

#	Areas of Focus	SCE Comments
1.	**Use of ADMS/DERMS for Provision of Variable Operating Envelopes on Appropriately Instrumented Feeders**	• SCE's supports implementation: DERMS/ADMS includes requisite functionality to enable DOEs to address primary infrastructure constraints • Recommend pilots and limited deployment 2027-2028
2.	**Exploration of Existing AMI based Low Voltage System Modeling to Provide Operating Envelopes for Feeders not Served by ADMS/DERMS Solutions**	• The Sandia Labs methodology is unnecessary: SCE plans to model its entire distribution system, including secondary/low-voltage facilities in ADMS/DERMS. • ADMS/DERMS will have the ability to calculate and provide DOE for all parts of the distribution system
3.	**Exploration of Operating Envelopes' Use in Addressing Shared Secondary Constraints**	• ADMS/DERMS will communicate DOEs to Aggregators, who will communicate with the individual DERs • Pilots may be beneficial to further explore the envisioned capabilities
4.	**Appropriateness of Requiring Extended Volt/VAR and Volt/Watt Curves for Generating Assets Using Operating Envelopes on Shared Secondary Equipment**	• All agreed-upon IEEE 1547 functionalities have been incorporated into Rule 21. • SCE is open discussing expanded use of IEEE 1547 capabilities for generation customers, with the focus on identifying if and when it is appropriate to require the full existing function set based on system need, maturity, and implementation readiness. • Any consideration of additional functions beyond current IEEE 1547 requirements (e.g., rate of change of frequency) should be evaluated carefully to ensure clear system value, technical feasibility, and alignment with broader grid operations before being considered for mandatory adoption.

SCE Requests Clarification or Pausing on Four CPUC-Identified Topics

#	Areas of Focus	SCE Comments
5.	**Appropriate Role and Definition of Aggregator for the Purposes of Operating Envelopes**	• Aggregator should be defined as an entity bundling end use customers and/or small DERs together to provide grid services based on DOE provided by the DSO using IEEE 2030.5. • An Aggregator may also serve as the protocol translating entity which converts IEEE 2030.5 to the protocol used by the aggregated DERs.
6.	**Potential Modifications to the 2030.5 Communications/CSIP**	• SCE's implementation of 2030.5 is aligned with the requirements of Rule 21 and is capable of DOE via CSIP and CSIP-Australia. • Upcoming revisions to CSIP will standardize dynamic operating envelopes. • The use of 2030.5 does not limit an Aggregator's ability to translate other protocols to achieve interoperability.
7.	**Alignment of Dynamic Rates with Variable Operating Envelopes**	• Significant analysis is needed to determine if, and under what circumstances, a customer can enroll in dynamic rates and a dynamic control program.
8.	**Non-bridging solutions**	See Next Slide

Flexibility Plays a Critical Role in Grid Orchestration

		Timing of Agreement	
		Before Energization	**After Energization**

Mode of Operation	**Temporary**	**Conventional "bridge to wires" approach.**
		• Benefit: accelerates energization
		• Customer demand will be limited *until* upstream capacity is constructed
			(New) DER Orchestration Programs
			• Similar to Load Flex considered in EIS 2
			• Benefits:
			  • Improve grid utilization; avoid *other* upstream capacity projects
			  • Local outage mitigation
			• Customer demand will be limited based on program rules, so long as customer is enrolled

	Permanent	**"Bridge + Permanent"**
		• Upstream capacity will not be constructed
		  • Benefit: avoiding grid upgrade costs (paid for by all customers)
		• May also avoid R15 distribution line upgrade:
		  • Benefit: avoid these costs, allocated to the *new* customer
		• Customer demand will be permanently limited
			(New) DER Orchestration Programs with Permanent Enrollment
			• Benefits: similar to above, but greater, given certainty of permanent reduction
			• Customer demand will be permanently limited

SDGE™

High DER Future – R.21-06-017
All-Party Meeting

February 20, 2026

Agenda

- Opening Remarks
- SDG&E Grid Modernization Vision
- Use of ADMS/DERMS for Provision of Variable Operating Envelopes
- IEEE 2030.5 Communications/CSIP
- Conclusion

Opening Remarks

- Appreciate CPUC convening this workshop to explore operating envelopes/flexible connections and implementation pathways
- SDG&E’s objective today is to gather information and contribute constructively to the conversation
  - Share background on SDG&E’s Grid Modernization Vision
  - Provide a summary of SDG&E’s ADMS/DERMS readiness
  - Listen and learn from other utilities, industry, and stakeholders
- SDG&E is not positioned today to deploy a standardized, systemwide dynamic operating envelope offering
  - Near-term feasibility would require targeted, proof-of-concept or pilot-scale applications with clear scope and measurable outcomes
- SDG&E looks forward to the dialogue and Q&A

Opening Remarks continued…

- Prepared slides focus on SDG&E's current ADMS/DERMS readiness, consistent with SDG&E's comments on the record.
- For the remaining topics, SDG&E is here to listen, learn, and support Q&A with available SMEs.
- Shared objective: discuss concepts, pilots, use cases, and customer value.

SDG&E Grid Modernization Vision

*SDG&E's Grid Modernization vision is to build a **flexible, customer-centered grid** that accommodates choice while **maintaining affordability and reliability**. By reinforcing the foundational capabilities needed to operate an increasingly dynamic distribution system safely and reliably, SDG&E **enables customers to adopt new technologies at their own pace**. The strategy **prioritizes utility investments that address near-term operational needs** while intentionally preserving **room for evolving technologies, market developments, and regulatory direction**. This approach helps avoid unnecessary or premature spending as future grid modernization requirements continue to take shape.*

ADMS/DERMS Roadmap and Capabilities

ADMS/DERMS-Enabled Variable Operating Envelopes

- **Operating Envelopes:**
  - Static: fixed limit
  - Variable (e.g., day-ahead); scheduled profile
  - Dynamic: hour-ahead, near-real-time
- **Primary Use Cases:**
  - Bridging: offer time-varying non-firm import/export limits to connect load/DER sooner where the primary feeder is the binding constraint
  - Abnormal operations: Operator-signaled limits during planned/emergent conditions
  - Normal operations: Operator-signaled limits during normal grid operations
- **Distribution constraint/problem being solved**
  - Bridging: Time-varying available capacity on distribution feeders (thermal/voltage constraints)
  - Abnormal operations: reliability risk during abnormal conditions where targeted load reduction could reduce equipment stress or improve restoration outcomes
- **Readiness and timeframe**
  - Requires consistent method to compute and communicate limits while maintaining safety and reliability
  - Requires validated models and telemetry coverage, short-term forecasting/analytics, DERMS integration, and measurement and validation

Hierarchy Operationalization of DERs

Energy Market Integration

- **Regulatory and Market Framework**
- Dependent on regulatory framework, pricing structures, prioritization, and value proposition.
- **Utilizes DERMS data**
- Ensures equitable participation of utilities and customers in the wholesale distribution market.

DERMS

- **Integration System**
- Relies on ADMS and proof of concept insights to manage and optimize DER integration.
- **Ensures grid stability and efficiency**
- Uses advanced data and insights to maintain a reliable and efficient grid.

Proof-of-Concept Initiatives

We are here

- **Tests and refines grid services**
- Various initiatives
- **Leverages DERMS components**
- Proof of concept initiatives for communications, pricing, performance, and visibility

Advance Distribution Management System (ADMS)

- **Integrates additional functionalities**
- FLA, FLM, FLISR.
- **Enhances grid management**
- Builds on DMS inputs

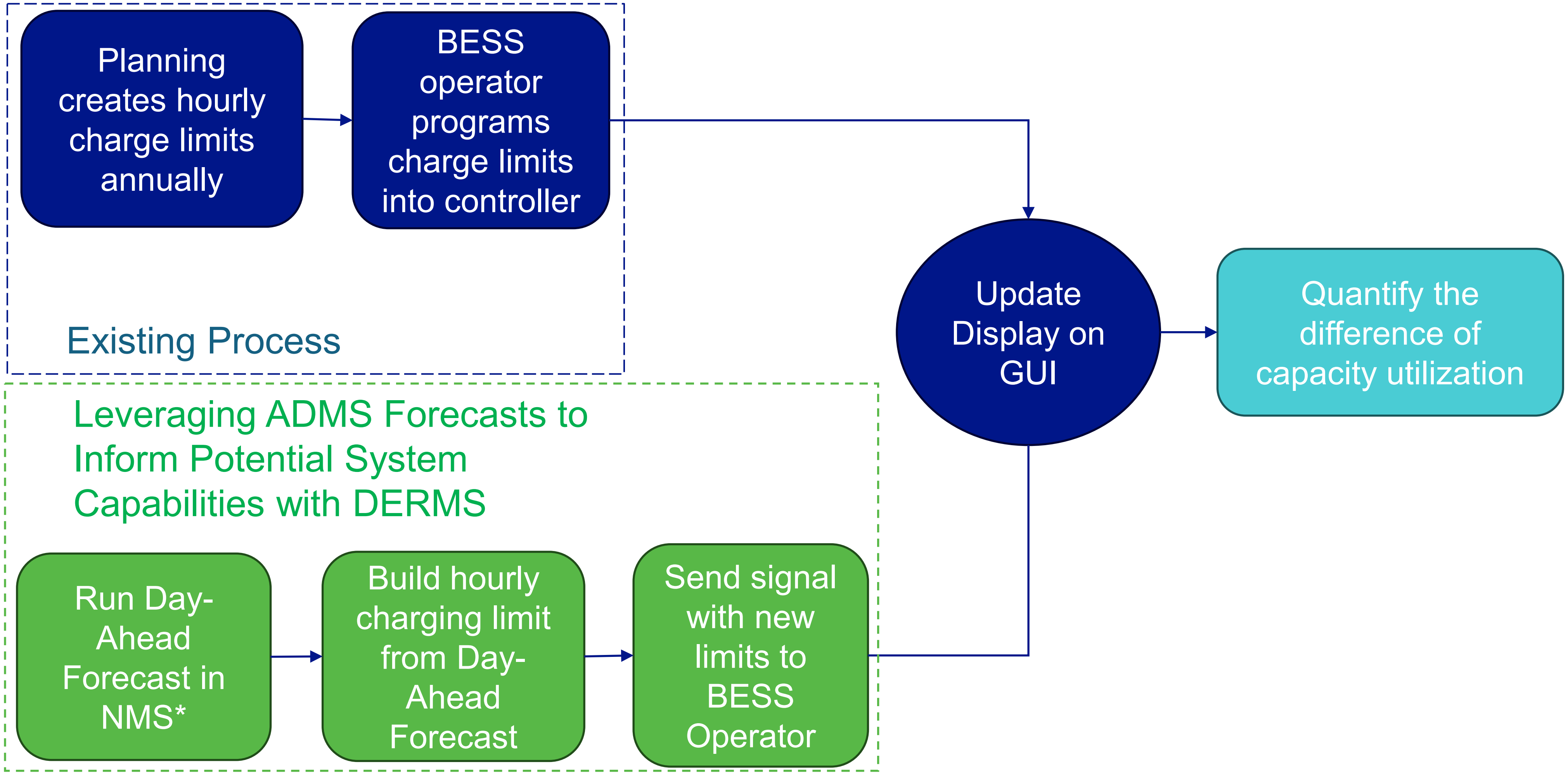
Distribution Management System (DMS)

- **Data inputs**
- Crucial for real-time monitoring and control
- **Foundation for ADMS**
- Ensures efficient, reliable operations

Capabilities

- **What Exists Today:**
  - Static operational envelopes
  - Limited capabilities of DER asset signaling
  - Small-scale feeder-level proof-of-concept forecasting and analysis (not systemwide customer-level forecasting).
  - Partial DER modeling within ADMS
- **What Doesn't Exist:**
  - High-quality, systemwide telemetry enabling full operating envelope calculations
  - Scalable, accurate short-term forecasting platform (day-ahead/hour-ahead) designed for broad deployment.
  - Fully integrated operational DERMS environment.
  - System wide communications ecosystem capable of reliably reaching diverse device types at scale.

Proof of Concept Initiative Utilizing DERMS



*Additional evidence is needed to confirm whether these technologies can be viably and cost-effectively scaled to support territory-wide dynamic operability.

Potential Modifications to the 2030.5 Communications/CSIP

IEEE 2030.5

- **Primary use cases**
  - IEEE 2030.5 is a communications method to deliver settings/controls to DER field devices and receive operational data from DER devices.
  - These signals are intended to utilize available IEEE 1547 control loops and parameters within the DER's controller to achieve the business objective.
- **Operational constraints/considerations**
  - Interoperability and scalability across a mixed installed base
  - DERMS deployment must consider integration of legacy devices
  - Network communication path may be variable
- **Other considerations**
  - Does not solve computation of operating envelopes
  - Still requires customer program rules or compensation
  - Requires measurement/verification or enforcement
- **Readiness/timeframe**
  - Currently in development projects on both DERMS and 2030.5 gateway integration
  - Pending positive project findings, Production deployments could potentially begin in 2028

Conclusion

Conclusion

- SDG&E is in proof-of-concept stage for operating envelope enablement
  - Enablement would require foundational work (telemetry/data readiness, modeling/forecasting capability, operational workflows, verification/enforcement)
  - Requires: concept refinement, targeted proof-of-concept/pilots, prior to a scalable offering
- Work in this space should be aligned with SDG&E's DERMS deployment
  - Foundational work and any targeted envelope activities should be coordinated with DERMS planning and rollout to avoid duplicative solutions
- Any near-term work would benefit from targeted Commission direction, with clear objectives and success criteria

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Q&A

FEBRUARY 20TH 2026 ALL-PARTY WORKSHOP

Brian Lydic, Chief Regulatory Engineer at IREC

Emma Hillman, Regulatory Engineer at IREC

IREC

Topic 4

Topic 4

Ruling requests "use of ADMS/DERMS for Provision of Variable Operating Envelopes on Appropriately Instrumented Feeders."

- We would like to clarify what it means to use DERMS for the provision of variable operating envelopes.
- To facilitate this clarification, we'd like there to be a consensus on the definition of "DERMS."
- We would like clarity on how DERMS fits into each workshop topic.

Starting Point for DERMS Definition - A software platform to manage and coordinate the operation of distributed energy resources in the electric grid.

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Topic 4

There are several types of DERMS and communications mediums/topologies being discussed:

- ADMS-based
  - Relies solely on SCADA data
  - Includes state estimation power flows
- Model-free hosting capacity analysis
  - Centralized
  - Decentralized
- Communication topology options:
  - Private networks
    - Cellular/radio
    - Fiber
    - AMI
  - Internet

Topic 5

Topic 5

Ruling requests whether to explore the Sandia Labs methodology and additional methodologies for modeling the low voltage grid using historical AMI data.

- Yes, we would like there to be further exploration of model-free hosting capacity analysis methodologies for the low voltage system using existing AMI data and assessment of their ability to provide variable operating envelopes.
- Recommended model-free hosting capacity analysis methodologies to investigate are:
  - Centralized
    - United Power Corporation used the Sandia Labs MoHCA methodology to create model-free hosting capacity maps*. **United Power Corporation has not used the MoHCA methodology to create variable operating envelopes.**
    - The University of Melbourne proposed a way to implement their Model-Free **Operating Envelopes** Architecture within the AusNet Services utility.
    - South Australia Power Networks (SAPN) utility used a "Template-based" methodology to create model-free hosting capacity maps ***and*** **used the maps to develop variable operating envelopes.**
  - Decentralized, grid-edge calculations of utility managed peer-to-peer communicating smart meters downstream of secondary distribution constraints.

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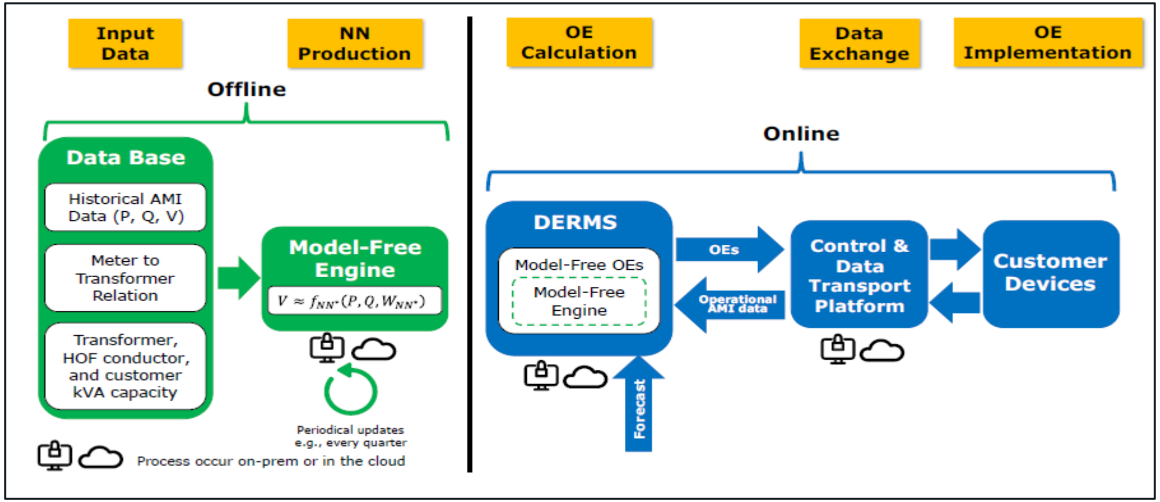
*"Model-Free Hosting Capacity Analysis," SNL and NRECA, https://www.cooperative.com/programs-services/bts/Documents/Reports/del0.3_-_MOHCA_NRECA_Final_Report.pdf

University of Melbourne Model -Free Example

The University of Melbourne proposed a way to implement their Model-Free Operating Envelopes Architecture within the AusNet Services utility to estimate hosting capacity without a full low voltage electric model. The proposed model uses historical smart meter data and network information to develop a model-free engine. Then either forecasts *or* operational AMI data of participating customers is added to the model-free engine to calculate variable operating envelopes that are sent to low voltage DERs.

University of Melbourne Model-Free Operating Envelopes Implementation Architecture



Source of info and graphic: Bassi, L. Ochoa, TAlpcan, C. Leckie, "Final Report:Model-Free Operating Envelopes," UoM-C4NET-Model-Free_OEs-FinalReport_v02. 2nd August 2023.

SAPN Template Model

The SAPN Tesla Advanced VPP Grid Integration and Flexible Exports for Solar PV trails estimated hosting capacity without a full low voltage electric model. They modeled 17 prototype low voltage feeders in detail and characterized other feeders as one of these 17 prototypes. They used a sample set of historical meter data to develop prototypical load profiles and eventually telemetered data to retroactively tune the load model. The hosting capacity estimate is used to create variable operating envelopes.

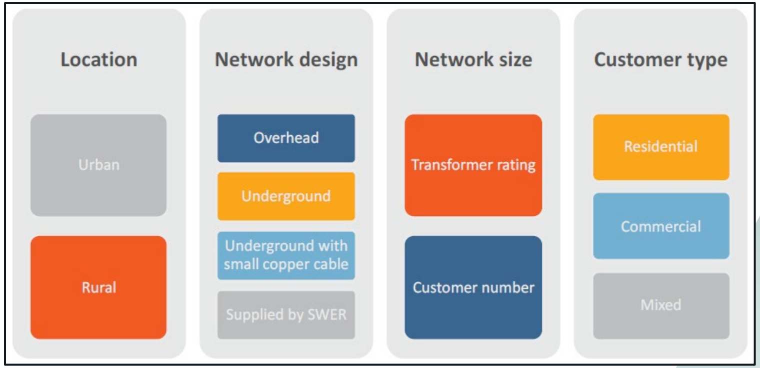
SAPN Hosting Capacity Estimation Components

Network model
- 17 low voltage areas modelled in detail
- Every LV feeder is mapped to one of the 17 prototypes, parameterised by its specific configuration
- Thermal limits set according to transformer rating
- Template-based voltage limits – based on customer & conductor type and geographical location

Solar PV model
- Location-based solar model using historical "estimated actuals" from ANU Solcast project
- Enhanced with solar insolation data from Weatherzone (forecasts, updated every 15 min)
- Scaled by installed PV capacity and conversion factor from W/m2

Load model
- Based on analysis of sample set of historical smart meter data by the University of Adelaide – developed load profiles for Commercial, Residential, Residential Hot Water
- Profiles selected and scaled based on temperatures from Weatherzone (forecasts, updated every 15 minutes)
- Scaled by average demand for each load category

Criteria used to select the sample set of LV feeders used in the hosting capacity model

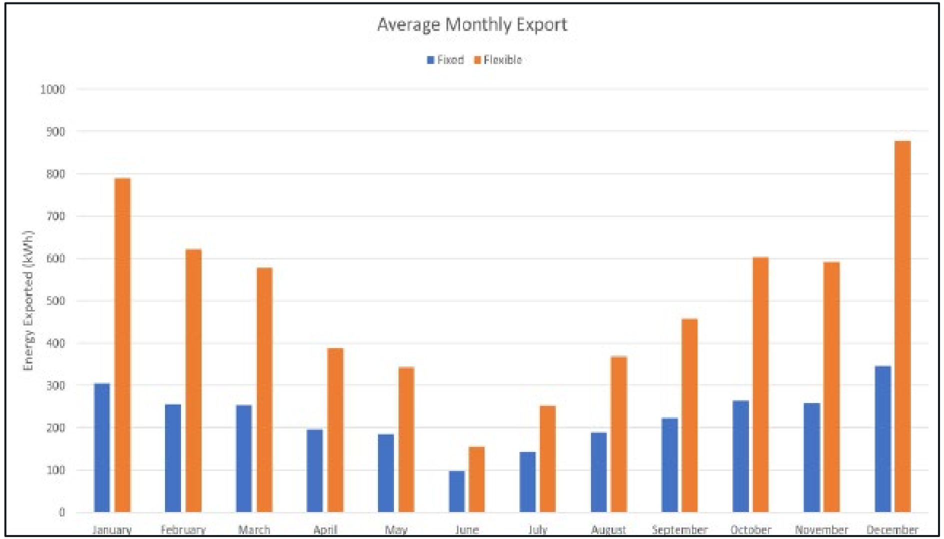


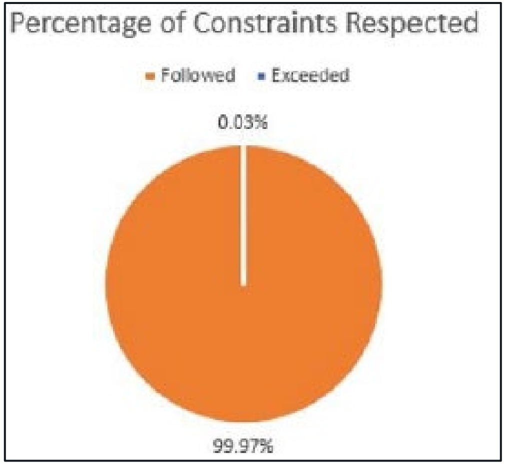
*"Flexible Exports for solar PV", SA Power Networks and AusNet Services, Final trial report v1.3, 19 October 2023, https://arena.gov.au/assets/2024/01/SA-Power-Networks-Flexible-Exports-for-Solar-PV-Trial-Final-Report.pdf

*"Advanced VPP Grid Integration report", SA Power Networks, Tesla, and CSIRO, Knowledge Sharing Report v1.0, 25 May 2021.

SAPN Template Model Results

In the SAPN Flexible Exports for Solar PV trials, exported energy approximately doubled each month, and 99.97% of 5-minute interval flexible export limits were followed.





*Flexible Exports for solar PV", SA Power Networks and AusNet Services, Final trial report v1.3, 19 October 2023, https://arena.gov.au/assets/2024/01/SA-Power-Networks-Flexible-Exports-for-Solar-PV-Trial-Final-Report.pdf

Topic 5

Ruling requests costs and benefits for all topic areas. This topic is on using AMI based low voltage system modeling to provide operating envelopes.

- More investigation and transparency is needed on the benefits and trade offs of different **hosting capacity analysis methodologies** to calculate variable operating envelopes.
- The SAPN cost benefit analysis compared **two hosting capacity analysis methodologies** to calculate variable operating envelopes for DERs in the low voltage network*.
- The SAPN cost benefit analysis helped facilitate more formal considerations of alternatives amongst stakeholders**.

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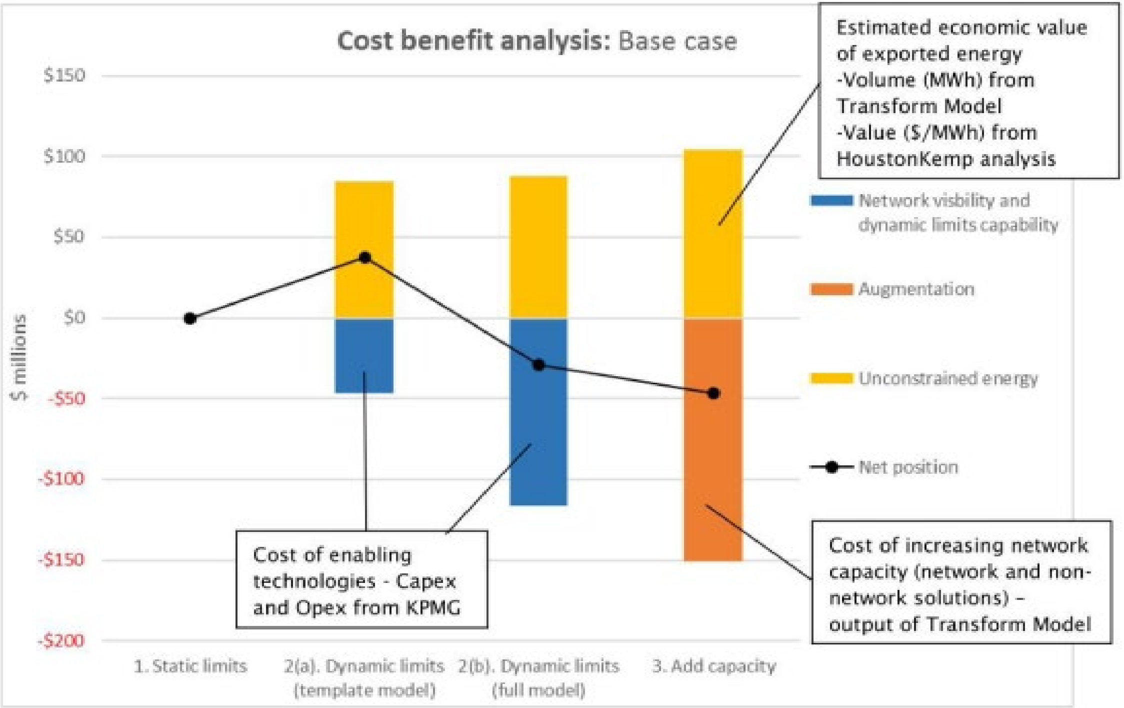
*Supporting Document 5.21, "EA Tech – LV Management Strategy", 2020-2025 Regulatory Proposal, 18 Dec. 2018.
**EA Technology, "DER and LV management: Finding the least-cost strategy" for South Australia Power Networks, https://eatechnology.com/media/nsihkwrd/aus-case-study-sapn.pdf

SAPN Cost Benefit Analysis Results



Source: EA Technology, "DER and LV management: Finding the least-cost strategy" for South Australia Power Networks, https://eatechnology.com/media/nsihkwrd/aus-case-study-sapn.pdf

SAPN conducted and documented* a cost benefit analysis of DER management strategies on the low voltage network.

*Supporting Document 5.21, "EA Tech– LV Management Strategy", 2020-2025 Regulatory Proposal, 18 Dec. 2018.

SAPN Cost Benefit Analysis Methodology

	Static Limits	**Dynamic Limits (Template Model)** *A Variable Operating Envelope Solution*	**Dynamic Limits (Full Model)** *A Variable Operating Envelope Solution*	**Add Capacity** *Not a Variable Operating Envelope Solution*
Costs	Base case – costs $0 to do nothing	DER Management Platform CAPEX and OPEX for a Template Electrical Network Model	DER Management Platform CAPEX and OPEX for a Full Electrical Network Model	Traditional wire upgrades, batteries, and third-party network contracts
Benefits	Base case – $0 in benefits to do nothing	Additional Energy Exported relative to Static Limit (Avoided dispatch cost of alternative generation)	Additional Energy Exported relative to Static Limit (Avoided dispatch cost of alternative generation)	Additional Energy Exported relative to Static Limit (Avoided dispatch cost of alternative generation)

Source: *Supporting Document 5.21, “EA Tech– LV Management Strategy”, 2020-2025 Regulatory Proposal, 18 Dec. 2018.

Topic 6

Topic 6

Ruling requests discussion on "exploration of operating envelopes' use in addressing shared secondary constraints."

- More **investigation** and **transparency** is needed to understand the **value** and **urgency** of using **static** and/or **variable** operating envelopes to address shared secondary constraints.
- More discussion is needed on the considerations for letting customers with shared secondary constraints choose between static and variable operating envelopes.
- Recommended to further investigate the value of static and variable operating envelopes as non-bridging solutions.

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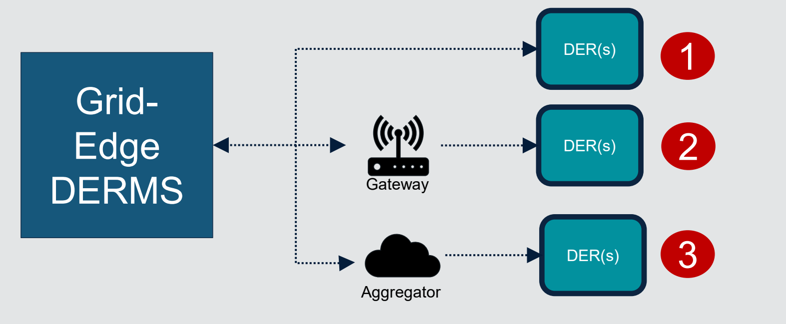
Topic 6

Ruling requests discussion on current platforms capable of "aggregator mediated load and generation control…on individual sites"

We would like to confirm our understanding that "aggregator" mediated load and generation is one of **four** strategies technically capable of **managing variable operating envelopes** to address shared secondary constraints.

Centralized Utility Controlled Grid-Edge DERMS



Decentralized Utility Managed Smart Meter Peer-to-Peer Comms

Communications Link

More formal investigation and transparency is needed to facilitate productive conversations on the benefits, trade-offs, and applicability of <u>all four solutions</u> for the low voltage DER flexible use case.

Connected load and Distribution Planning

- Connected load concept in LLP Ruling allows for static operating envelopes via PCS or other methods
  - The ruling appears to require allowing a customer to change their load profile and load factor without notification to the IOU
  - If IOUs are relying on profiles and load factors (rather than "nameplate load") to calculate capacity, then load could exceed existing equipment ratings for certain hours (see following example)

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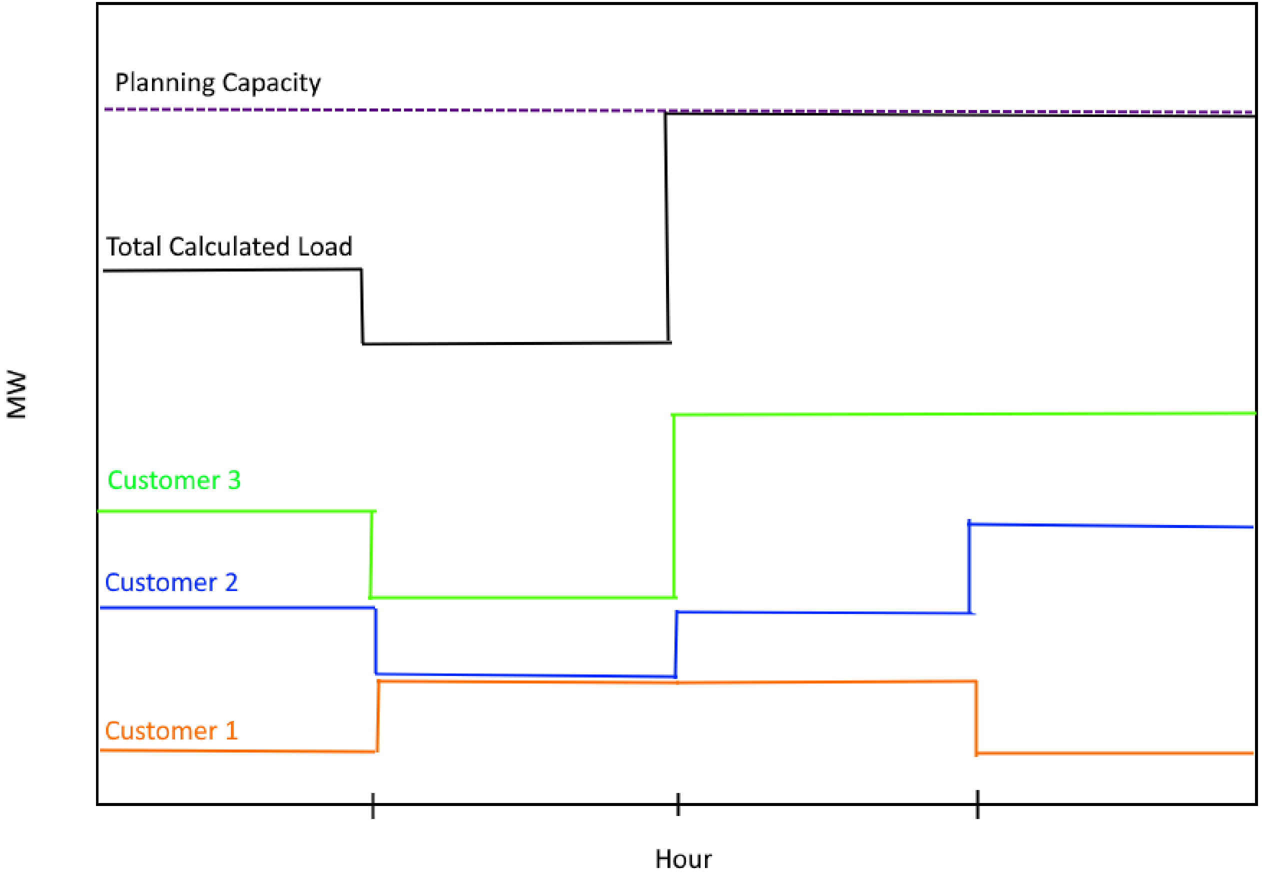
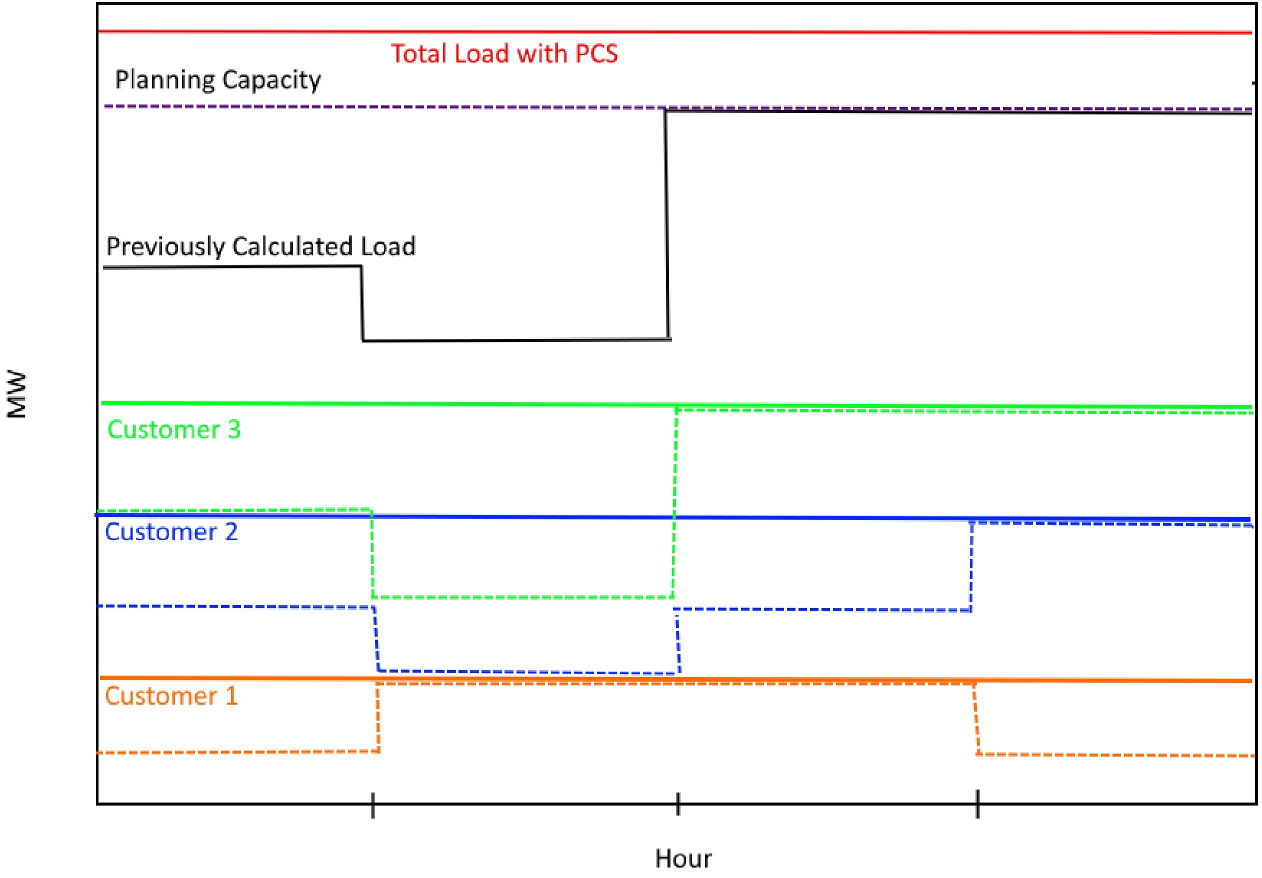
Connected load profiles today



Connected loads with PCS



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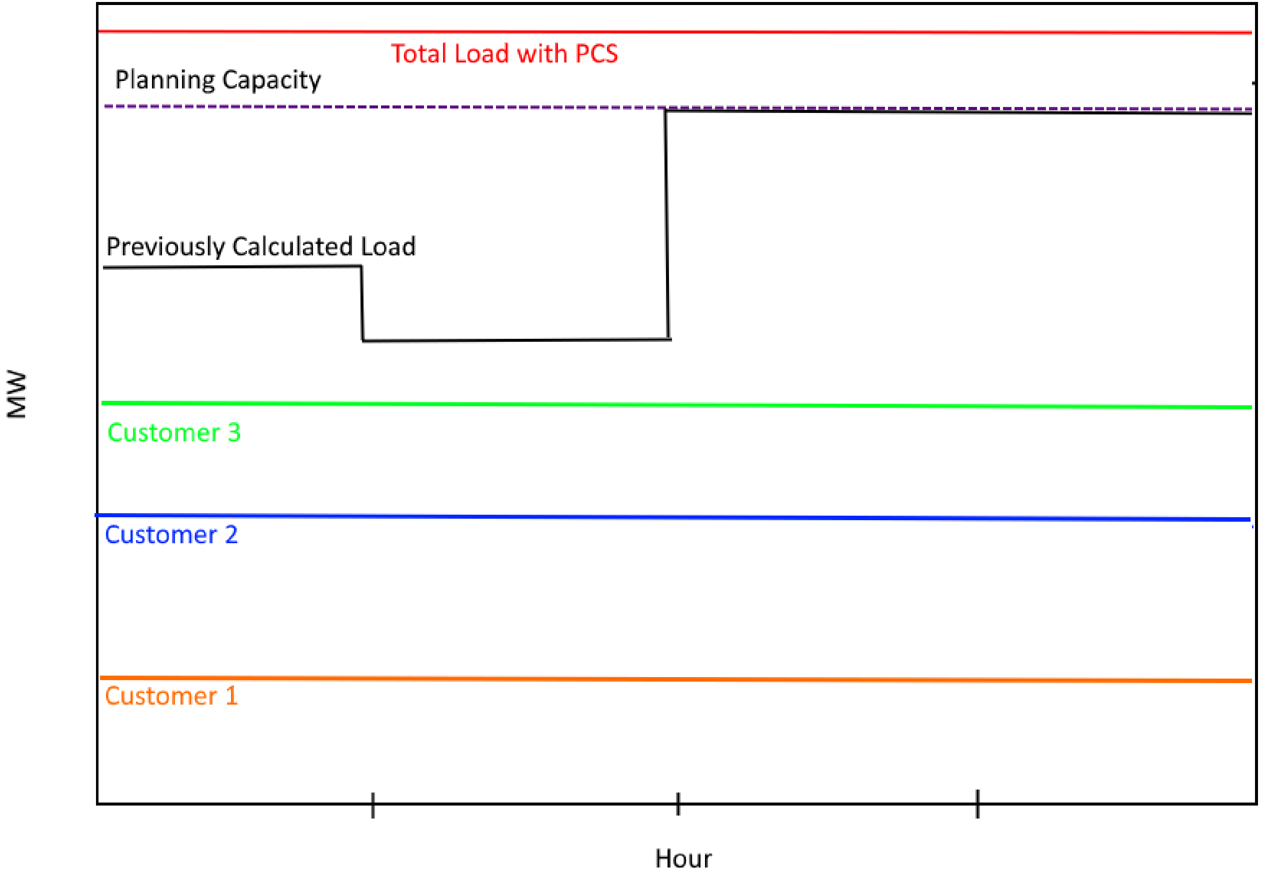
Connected loads with PCS



Topic 7

Topic 7

Ruling requests discussion on "whether and when it may be appropriate to require generation customers to utilize the full set of IEEE 1547 capabilities for these functions"

1 **Scheduled or Dynamic Operating Envelope of Active Power**

Operating Envelope activates to address shared secondary equipment voltage constraint(s) complimented w/ volt/VAR and volt-watt.

Consider influence of extended autonomous volt/VAR and volt-watt curves on Operating Envelopes.

2 **Autonomous Volt/VAR Curve**

Investigate cost and benefit of extending customer's Volt/VAR to increase local system's hosting capacity.

Investigate cost and benefit of extending customer's Volt/VAR to expand their own operating envelope.

Investigate if curve is system-wide/customer-specific and all customers/Flex IX customers.

3 **Autonomous Volt-Watt Curve**

Investigate cost and benefit of extending customer's Volt-Watt to reduce conservatism of their own operating envelope.

Potential extended Volt-Watt curve to be Flex IX customer-specific to avoid unnecessary curtailment of other systems.

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Topic 7

Ruling requests discussion on "whether and when it may be appropriate to require generation customers to utilize the full set of IEEE 1547 capabilities for these functions"

- Investigate autonomous volt-watt as primary flexible interconnection control for voltage-constrained sites
- Would likely be least-cost solution, and available today

Topic 9

Topic 9

Potential Modifications to the 2030.5 Communications/CSIP

- We recommend relying on experts from a diversity of stakeholders to provide comment on this topic.

IREC

IREC Contact Information

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IREC

CALCCA
ADVANCING LOCAL ENERGY CHOICE cal-cca.org

Flexible Connections All-Party Workshop
R.21-06-017

February 20, 2026

Who Are Community Choice Aggregators?

CalCCA Interactive CCA Map & Address Lookup:
https://cal-cca.org/cca-map/

CCA Launch Timeline

California CCAs: By the Numbers

Number of California communities served by CCAs: 229

Number of Counties with CCA: 21 of 58 counties (36%)

Number of Cities/Towns with CCA: 208 of 483 Cities (43%)

California Population served by CCAs: 16 Million+ (38%)

2025 and 2026 CCA Expansions

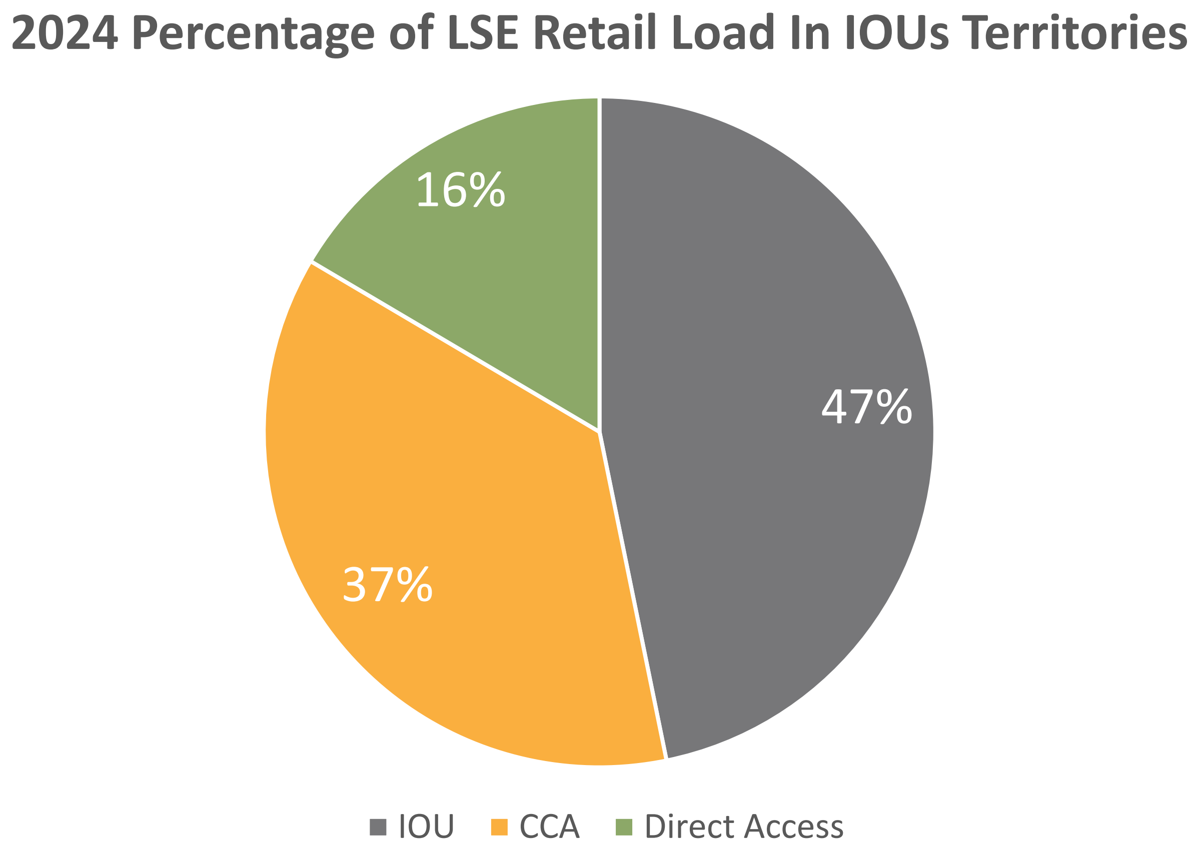
2025

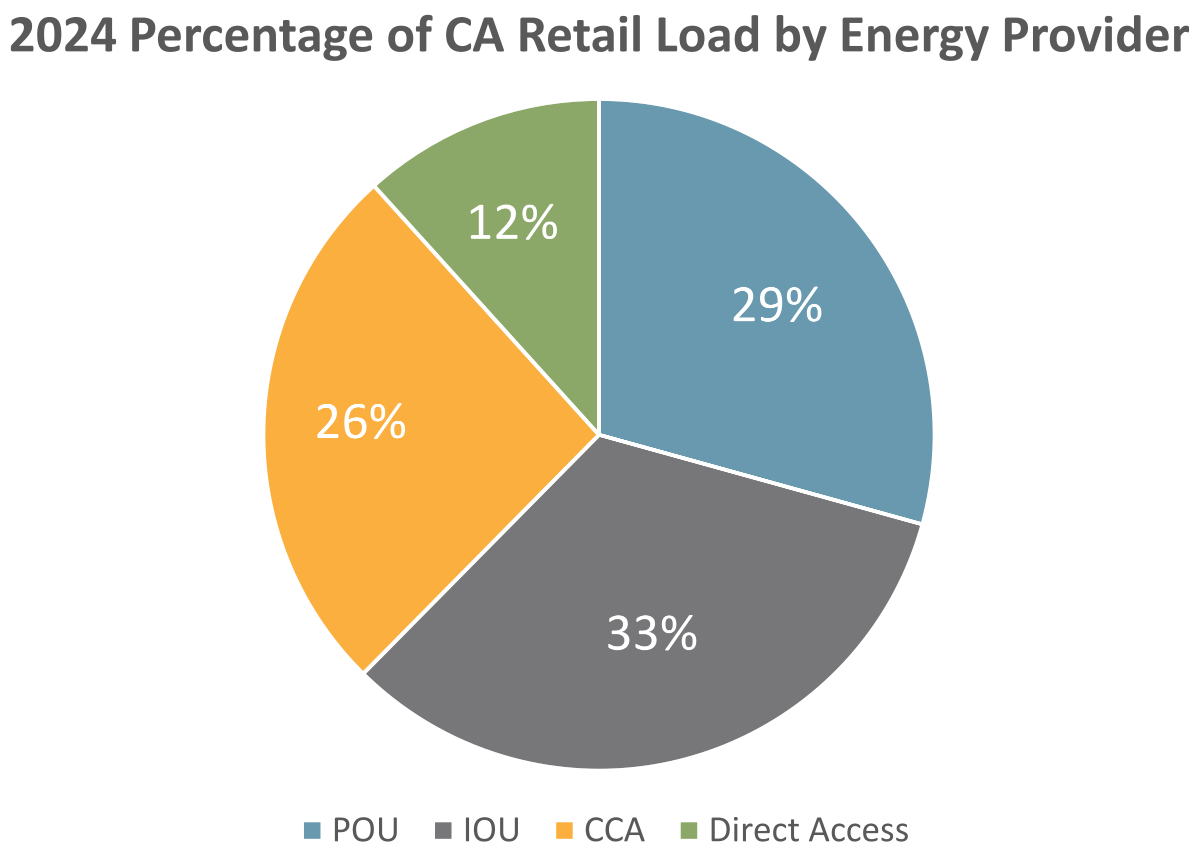
CCA	New/Expansion	Cities/Counties	Start of Service
Central Coast Community Energy	Expansion	County of SLO, City of Atascadero	January 2025
Ava Community Energy	Expansion	City of Stockton and Lathrop	April 2025
Marin Clean Energy	Expansion	City of Hercules	April 2025
Clean Power Alliance	Expansion	Cities of La Canada Flintridge, Lynwood, Port Hueneme	October 2025

2026

CCA	New/Expansion	Cities/Counties	Start of Service
Ava Community Energy	Expansion	County of San Joaquin	May 2026
Orange County Power Authority	Expansion	City of Fountain Valley	October 2026

2024 Percentage of CA Retail Load by Energy Provider (Electricity deliveries GWh to End Users)





Source: 2023 IEPR Forecast. California Energy Demand 2023-2040 Forecast - Planning Forecast

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Why Are CCAs Interested in Flexible Service Connections?

CCA APPEAL

- Climate Impact
- Local, transparent decision-making/accountability
- Rate competition/rate stability
- Green energy choices
- Community-based programs
- Economic Development, Jobs

CCA Programs

- As CCAs continue to grow and flourish in California, they are advancing innovative, industry-leading projects and programs
- Many are now focusing on DERs, including Virtual Power Plants
- Several CCAs now operate DERMS platforms to directly control customer DERs and smart appliances

"CCAs can design and deploy innovative initiatives and community-centered programs that provide financial and environmental benefits and can respond to communities' needs."

-UCLA Luskin Center for Innovation

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CALCCA
ADVANCING LOCAL ENERGY CHOICE

Sonoma Clean Power Your Public Electricity Provider

Hablamos Español

Meetings & Agendas MENU

Alerts Through GridSavvy Rewards

Stay Cool, Save Energy, and Keep Your Neighborhood Bright With GridSavvy Rewards From Sonoma Clean Power.

GET $25 WHEN YOU ENROLL

Save Energy. Share Energy. This Summer and Beyond.

When it's really hot, everyone uses more electricity. To make sure there's enough to go around, there's an easy way to help: **Save Energy. Share Energy.** Saving energy when asked helps your whole neighborhood. When you save energy, you share energy, to help keep the lights on in the neighborhood **all summer long**.

Earn rewards by lowering your energy use when electricity use is high. By reducing electricity use during peak hours, you can help decrease the need for natural gas power plants and prevent power outages.

When you sign up for GridSavvy Rewards, you'll get paid for helping us power the electric grid with more local, clean energy. SCP will send an energy saving alert when there is high demand for electricity. You choose how to reduce your energy use.

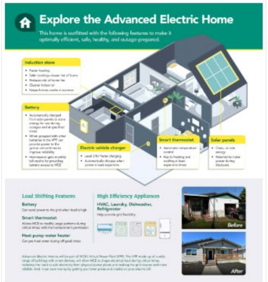
SIGN ME UP!

MCE

How to Help California's Grid? Go Virtual

At first glance, there's nothing atypical about the small gray house located on a quiet residential street in Richmond, Calif. But look further and you'll see that it's the first piece of a revolutionary new type of power plant. Unlike traditional plants, you won't find any massive cooling towers or transmission lines. That's because this electrified home is part of a virtual power plant, or VPP.

How It Works



The homes MCE is equipping to participate in its VPP are outfitted with numerous grid-smart devices that not only provide grid flexibility but also make for a better experience for the homeowner.

VPP in the News

News Release – November 3, 2025

Peninsula Clean Energy, Silicon Valley Clean Energy Jointly Launch Demand Flexibility Initiatives

Lunar Energy's Gridshare software will enable new battery and other programs to reduce customer energy bills and harmful emissions

PENINSULA CLEAN ENERGY SILICON VALLEY CLEAN ENERGY

REDWOOD CITY/SUNNYVALE, CA – Peninsula Clean Energy (PCE) and Silicon Valley Clean Energy (SVCE) are jointly launching cutting-edge demand flexibility efforts, highlighted by a Distributed Energy Resource Management System (DERMS) that will support a range of new programs.

The DERMS is a powerful software platform that both agencies will use as a foundation to expand their clean and smart energy programs. The new platform will enable participating customers to easily, automatically and comfortably shift daily electricity use – earning them direct bill savings, while also helping to reduce grid costs and harmful emissions.

PCE and SVCE have contracted with Mountain View-based Lunar Energy for its Gridshare DERMS platform to connect, control and optimize devices located at customer sites.

ORANGE COUNTY POWER AUTHORITY YOUR CLEAN ENERGY CHOICE

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Board & Committee Meetings Your Options Billing & Rates Energy Programs About Us Resources

Residential Battery Rebate Program

Power up and protect your home with a battery energy storage system

Overview Eligibility Resources Application

Power Up and Reduce Electricity Costs with a Home Battery

Orange County Power Authority's (OCPA) Residential Battery Storage Rebate Program helps customers manage their energy consumption and save money by storing electricity during lower-cost, off-peak hours for use during more expensive, on-peak hours ("load shifting"). Adding battery backup can protect your home from outages and help strengthen the electric grid. A battery will also reduce greenhouse gas emissions.

Rebate amount per customer: $1,000.

Clean Power Alliance Approves New Program to Install Virtual Power Plant and Provide Low Income Customers Access to Solar Energy at No Cost

CPA CLEAN POWER ALLIANCE

Clean Power Alliance Approves New Program to Install Virtual Power Plant and Provide Low Income Customers Access to Solar Energy at No Cost

CPA will work with Haven Energy to install networked solar and battery storage systems on eligible low-income residents' homes to provide localized clean power and significant savings on customer electricity bills while managing peak energy demand

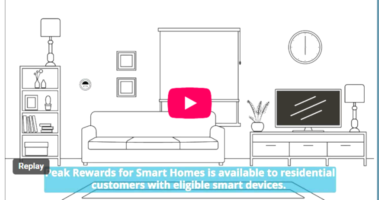
SAN JOSE CLEAN ENERGY

ABOUT RESIDENTS BUSINESSES SAVINGS SUBSCRIBE CONTACT US ESPAÑOL TIẾNG VIỆT

PEAK REWARDS FOR SMART HOMES

Let your smart device earn you rewards!

Peak Rewards for Smart Homes makes it easy to earn rewards. Simply enroll an eligible smart device in the program and you'll automatically start earning rewards each quarter. We communicate directly with your device to make small adjustments that keep you comfortable and earn you rewards. You are always in control and can override our signals when needed.



Ava Community Energy Announces Ambitious Virtual Power Plant Initiative to Help its 2M Customers Optimize Their Energy Investments While Relieving Stress on the Grid

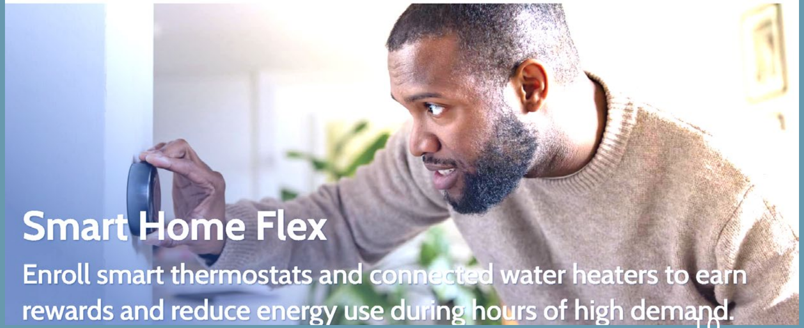
April 24, 2025

Lunar Energy's Gridshare DERMS Platform Selected to Underpin the Effort

Oakland, CA April 24, 2025 – Ava Community Energy (Ava) today announced the launch of its comprehensive Virtual Power Plant (VPP) strategy. VPPs are systems that aggregate distributed energy resources (DERS), such as electric vehicles and home batteries, so they can be controlled remotely to enhance grid reliability and lower costs.

SAN DIEGO COMMUNITY POWER

ABOUT COMMUNITY POWER WAYS TO SAVE BILLING & RATES HOW DO I?



CALCCA ADVANCING LOCAL ENERGY CHOICE

CalCCA Positions on Flexible Connection Topics

CalCCA Positions on Flexible Connection Topics

- **CCAs are open to engaging with IOUs to accelerate deployment of grid-edge capabilities**
- OpenADR is complementary to IEEE 2030.5, but more cost-effective, scalable and better-suited for demand flexibility events or pricing signals
- **The definition of 'aggregator' should not be limited to an IEEE 2030.5 cloud service provider**
- DERs and grid-edge DERMS could serve as non-bridging solutions, subject to cost-effectiveness and equity considerations
- **The IOUs should establish flexible connection pilot programs for secondary system customers**
- Customers with variable operating envelopes should not be defaulted to dynamic rates

Optimizing Existing Grid Capacity Requires Coordination Between IOUs and Aggregators

- **Without grid-edge DERMS capabilities, DERs could inadvertently exacerbate local (circuit-, line-segment-, or substation-level) capacity constraints**
- Leveraging *all DERs,* including non-IOU DERS, is crucial to optimizing existing grid capacity and helping lower costs
- **CCAs have a unique role as not-for-profit LSEs that can both help reduce systems costs (*e.g.*, RA, grid investments) and share value with ratepayers**
- However, CCAs need timely access to grid data and/or signals from IOUs to accomplish these grid-level objectives

OpenADR and IEEE 2030.5 are Compatible and Complementary

- **IEEE 2030.5 allows for precise control of individual inverter-based DER, but is not efficiently or economically scalable to millions of devices**
  - IEEE 2030.5 is designed for inverter-based resources, but not smart appliances
- **OpenADR is better suited to delivering price- or event-based signals to aggregators and end-users, making it scalable and reducing the burden on DSOs**
  - OpenADR can convey precise device-level signals via IEEE 2030.5, SunSpec Modbus, Matter, or other interoperability standards.
  - OpenADR can control inverter- and non-inverter-based resources
  - OpenADR offers greater flexibility and is more cost-effective to deploy at scale
  - Most IOUs already use OpenADR for their DR programs
- **The use of OpenADR and IEEE 2030.5 is compatible and complementary**

Aggregator Should Not Be Defined as Merely IEEE 2030.5 Cloud Services

- **Limiting 'Aggregators' to only IEEE 2030.5 cloud service providers could limit the participation of grid-edge DERMS providers using OpenADR or other communications protocols**
  - Many aggregators use other communications standards to control on-site inverters
- **Rule 21 does not preclude the use of other protocols**
  - While Rule 21 states the default application-level protocol shall be IEEE 2030.5, it also states that "other application-level protocols may be used by mutual agreement of the parties"

Dynamic Flexible Connections Should Be Considered for Non-Bridging Solutions

- **Non-bridging solutions should consider IOU and non-IOU solutions**
  - CCAs are particularly well-positioned to provide non-bridging flexible connection services as community-led, not-for-profit load-serving entities
- **Any proposed solutions should be subject to cost-effectiveness evaluations and equity considerations**

The IOUs Should Establish Flexible Connection Pilots for Secondary Service Customers

- **Grid-edge DERMS could enable participation of customers on the secondary system to participate in flexible connections**
  - Grid-leveraging using OpenADR may prove to be more cost-effective than enabling solely IEEE 2030.5 options
- **CCAs are open to exploring joint CCA-IOU pilot program opportunities**

Customers Should Not Be Opted Into Dynamic Rates

- **Customers with variable operating envelopes should not be opted into dynamic rates**
  - Customers should be given information regarding available dynamic rate pilots and offerings, but should not be automatically enrolled, regardless of the ability to opt out
- **Dynamic rates are still in pilot phases and pending evaluation on performance and cost-effectiveness**
  - Earlier evaluations did not find evidence of consistent or large changes in customer energy usage in response to hourly prices
- **Requiring customers to opt-out of dynamic rates could create confusion and discourage participation in flexible service options**

Non-Bridging Flexible Service Connections

February 20, 2026

Why *elective* non-bridging FSC?

A. Non-wires solutions are still needed to support distribution investment deferral & avoidance values

- "Top-down" approaches, like the DIDF and Partnership Pilot, were insufficient and structurally challenged
- ***Elective,* non-bridging FSC serves as a "bottom-up" approach for *interested* customers to proactively install hardware and/or software systems that help avoid distribution system upgrades**

B. The CPUC and utilities have already established the necessary foundation:

- Standardized flexible service connect offerings
- Utilities' customer-facing programs, support staff, and marketing (e.g., "Flex Connect")

Proposed Elective FSC Design Principles

1. Customers should be able to choose to participate in flexible service connections programs/tariffs as a non-bridging strategy

2. Customers should be offered an upfront incentive to offset the hardware and/or software costs incurred to implement FSC as a non-bridging strategy (e.g., NY LMTIP)

3. The total incentive budget should stay below the total value of distribution system avoidance & deferral, yielding a win-win situation for ratepayers and participating customers

4. Robust data collection and public reporting should be established to track whether the program is effective, informing the future availability of incentives