Track 2 Workshop Report: TSO-DSO Coordination

HIGH DISTRIBUTED ENERGY RESOURCES PROCEEDING (R.21-06-017)

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Workshop Report: TSO-DSO Coordination

High DER Track 2 (R.21-06-017)

Workshop Date: June 5, 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 2 focuses on developing new operational capabilities of the distribution system operator (DSO), including the orchestration of DERs. DER Orchestration is the coordinated management of DERs by a DSO. Using visibility, forecasting, and control/scheduling tools, DSOs identify location- and time-specific distribution needs and signal eligible DERs (directly or via aggregators) to deliver verifiable services that defer infrastructure investments, support electrification, improve grid reliability, and enhance customer value.

II. Introduction

The DER Orchestration Workshop 2: Developing a Transmission System Operator (TSO)-DSO Coordination Framework (the Workshop) was held on June 5, 2026, to further develop the record on the topics identified in the CPUC's March 23, 2026 Assigned Commissioner's Ruling on Track 1 and Track 2 Distributed Energy Resources Orchestration (the Ruling). The workshop brought together CPUC staff, the California Independent System Operator (the CAISO), investor-owned utilities (IOUs), community choice aggregators, DER advocates, service providers, and other stakeholders and was structured around three principal objectives.

The first was to enhance the CAISO DER visibility by improving access to data on DER capacity, schedules, and performance, thereby supporting accurate forecasting, market efficiency, and system reliability consistent with CAISO's coordination framework. The second was to strengthen TSO-DSO coordination by clarifying roles, responsibilities, and data-sharing protocols so that Distributed Energy Resource Management System (DERMS) development aligns with the CAISO's operational needs. The third was to align TSOs, DSOs, and other participating entities on shared priorities for DER integration and grid operations in a high-DER future.

These objectives were pursued through six key topics:

1. CAISO operational and forecasting challenges and DER visibility needs;
2. IOU/DSO DER data sharing capabilities;
3. Centralized data exchange and technology platform considerations from Open Access Technology International (OATI) and Piclo;
4. Open discussion on developing an operational TSO-DSO coordination framework;
5. Open discussion on forecasting integration and DER modeling alignment; and
6. Closing remarks and next steps.

III. Opening Remarks

The workshop opened with welcoming statements from CAISO, the California Energy Commission (CEC), and the CPUC. Anna McKenna, VP of Market Design and Analysis for the CAISO, welcomed participants and framed enhanced TSO-DSO coordination as a reliability and market-efficiency imperative given the rapid growth of DERs across the state. CEC Vice Chair Siva Gunda followed, anchoring the workshop's discussion in California's five energy-policy pillars – clean, reliable, affordable, equitable, and safe. He observed that California's bulk system may grow from approximately 100 gigawatts today to between 300 and 350 gigawatts, and that behind-the-meter solar, storage, and community-level DERs present significant opportunities to maximize resource utility while preserving reliability and affordability

CPUC Commissioner Darcie L. Houck then offered remarks emphasizing the importance of close coordination between the Commission and CAISO and the need to gain visibility into DERs to take full advantage of these resources. Administrative Law Judge (ALJ) Jack Chang introduced himself as one of the assigned ALJs on the proceeding and noted his interest in incorporating the day's discussion into the eventual Proposed Decision.

IV. Summary of Perspectives by Party

a. The CAISO

The CAISO provided an overview of the evolving DER landscape. Historically, coordination at the transmission-distribution interface was largely focused on interactions between CAISO and utility transmission operators. Today, there are many more entities influencing system conditions, including market and non-market DERs, utility and non-utility demand response providers, storage resources, and large flexible loads. The changing operating environment and state policy goals are creating new coordination needs that existing frameworks were not originally designed to address.

The CAISO provided an overview of the current state of operational coordination between the CAISO, the IOUs, and other entities that are responsible for DER integration and operation on the transmission and distribution system. The CAISO shared specific operational and market challenges the CAISO has experienced related to increased penetration of distribution-connected resources. The CAISO identified four key areas related to DER integration and operation that need to be addressed: 1) defining roles and responsibilities, 2) improving information and visibility, 3) improving operational forecasting, and 4) aligning operational coordination. First, the CAISO identified a need for alignment on roles and responsibilities for entities that operate systems that interact with DERs. Second, the CAISO identified the need for improved and consistent information and visibility into DER behavior to improve the CAISO's short-term forecasting by better capturing the impacts of DER behavior on load shapes. The CAISO highlighted that information and visibility is the foundation, but not the end goal, for both operational forecasting and operational coordination. Third, the CAISO identified the need to improve operational forecasting to better reflect DER behavior and load impacts in the first instance. Finally, the CAISO identified the need to align on best operational practices between transmission and distribution operators to address the current and future DER reality.

Given the issues and needs identified by the CAISO, the CAISO stated that the enhancements to coordination are supported. This includes DER data sharing and visibility, operational practices, and transmission and distribution operator coordination that the CAISO identified to bring reliability and economic benefits to the transmission and distribution systems through the operational coordination framework. The presentation highlighted several ways improved coordination can strengthen reliability, including through improved situational awareness, better understanding of DER behavior and net load conditions, faster identification and response to abnormal operating conditions, more effective management of transmission-distribution interactions, and reduced need for conservative operational actions resulting from uncertainty. The CAISO also identified affordability as a major value driver given the connection between operational uncertainty and customer costs. Improved forecast accuracy, improved market efficiency, reduced operational uncertainty, better utilization of lower-cost demand flexibility resources, and avoided unnecessary infrastructure investments where existing flexible resources can be leveraged more effectively allow for significant affordability benefits.

The CAISO shared that the proliferation of DERs that are not market participating have created new challenges from an operational perspective, given a complex landscape of visibility into different types of resources on the supply side and the demand side, and these may not be addressed through DER Orchestration. The CAISO explained that forecasting and operations lack consistent data. The CAISO further explained that current operating reality faces fragmented data flows, aggregation granularity inconsistency, and limited operational time frame awareness with distribution operators having limited visibility into the CAISO's actions and the CAISO having limited visibility into distribution-side actions.

On the market-participating side, the CAISO has a platform to reflect the attributes of demand flexibility through the CAISO's market models. This includes 1) the DER aggregation model for DERs with exporting capabilities, 2) the Reliability Demand Response Resource (RDRR) model that is triggered under reliability conditions in real time, and 3) the Proxy Demand Response (PDR) model which is considered "economic" demand response. The CAISO has visibility into the attributes and dispatch schedules of these resources. On the demand side, the CAISO considers load modifying resources where behavior is influenced by utility rates and DER utility programs that shape load but the CAISO has limited visibility into the operation and behavior of these resources as they are not market integrated, which poses forecasting and operational challenges. Similarly, the CAISO has limited visibility into emergency programs including the CEC's Demand Side Grid Support (DSGS) program and the CPUC's Emergency Load Reduction Program (ELRP) which are also not market integrated. To ensure that the CAISO is accurately forecasting and accessing demand, understanding DER planning characteristics, operational limits, and schedules is instrumental. Improving data sharing and visibility will allow for improved DER integrated and demand flexibility while improving reliability.

The CAISO shared that given the limited visibility into certain DERs and their behavior, the CAISO has observed several distinct operational and market challenges that it believes can be addressed through better operational coordination at the TSO/DSO level. First, the CAISO has observed sudden and distinct changes in load levels occurring at the top-of-the hour. This pattern has been observed across the three utility areas and has become more common. Top-of-the hour spikes diverge from the smoother transitions from hour to hour that CAISO has normally observed with impacts to the CAISO grid and market outcomes as well as beyond the CAISO balancing authority. Second, the CAISO has observed negative loads at certain substations, indicating the distribution system is feeding back power to the transmission system. DERs exporting into the bulk electric system runs the risk of overloads in situations where CAISO mitigation options are limited. Finally, the CAISO has observed that resources and loads can be modeled inconsistently between the CAISO and the utilities.

The CAISO emphasized that the challenges described above are not solely a visibility issue but reflect a broader need to maintain operational certainty in an increasing dynamic electric system on the demand side. The CAISO stated that improving coordination can enhance reliability, improve market efficiency, and create greater opportunities to utilize demand flexibility resources in support of both transmission and distribution system needs.

The CAISO shared a four-pillar framework that it believes will allow for a future where demand flexibility is reliably and economically integrated into grid operations and market optimization. The four pillars are: 1) Operational Coordination Framework, 2) Technology and Data Exchange, 3) Market Design, and 4) Policy and Regulatory Alignment. The CAISO presented on the first pillar and identified three key focus areas of the Operational Coordination Framework: 1) enhanced operational coordination, 2) information and visibility, and 3) operational forecasting. The CAISO reported on the approach to the Operational Coordination Framework and the deliverables anticipated in the coming years. The CAISO reported that the Operational Coordination Framework will come in two phases: first, understanding the current state of operational coordination and forecasting and information and visibility gaps, and second, leveraging learnings from the first phase to develop practical and scalable solutions. The CAISO is currently in the process of documenting current processes and known gaps, mapping the existing information exchange, and identifying solution design for data exchange that will inform trials which will ultimately inform value realization. Between 2026 and 2030, the CAISO plans to phase the implementation of forecasting and operational improvements. The CAISO is working with a wide range of stakeholders through its Expert Working Group and has developed an engagement plan that is iterative, allowing for consistent stakeholder and regulatory engagement as the CAISO continues to develop the Operational Coordination Framework and address the identified issues and challenges with DER proliferation and integration.

b. Pacific Gas and Electric

PG&E outlined the types of DER data PG&E has (and some it does not have), visibility across the transmission–distribution interface, and framed a phased "Crawl, Walk, Run" prototype focused on data sharing, customer privacy, and secure transmission between the CAISO and DSO.

Context Setting:

- Core problem: PG&E holds extensive customer DER-related data, but key data points live in separate, disconnected systems — interconnection records, program databases, grid, and billing systems.
- Sensitivity: Much of this data is personally identifiable information (PII), while sharing the data can be complex and costly, creating a tension between operational value and customer privacy.
- Key question: What data has value (and to whom)? Recognizing the sensitivities outlined above underscores the need to identify the most critical and highest value data to reduce system costs, enable customers to electrify sooner, reduces resource build, enables DERs to provide multiple services, and that improves situational awareness.

Data-Centric Workstreams (Crawl → Walk → Run)

Three parallel workstreams progress through maturity stages:

	CRAWL	WALK	RUN
Data	• Hypothesize on DER data sources of potential value • Pilot data sharing to determine the value provided by data type • Identify data quality concerns	• Build manual / automated data pipelines for high value data • Standardize data formats and models • Evaluate value of data vs costs of data sharing platform options	• Data shared with required quality, frequency, and scale • Automated data pipelines • Value of data outweighs costs of data sharing systems
Privacy	• Assess customer data privacy requirements • Map sensitive data fields across systems • Obtain required approvals for data sharing as needed	• Implement anonymization and aggregation rules as needed • Propose updates to anonymization rules if necessary	• Privacy-preserving analytics at scale
Secure Data Sharing	• Define minimum viable data sharing processes for TSO-DSO exchange • Establish secure transfer protocols	• Expand scope of shared data elements • Evaluate if existing data sharing tools should be expanded or new tools created	• Fully automated bidirectional sharing at the required frequency

The Transmission-Distribution (T&D) Prototype — Crawl Stage

- PG&E and CAISO jointly launched the T&D Interface Prototype in late 2025 to improve DER visibility, operational forecasting, and T&D coordination across selected regions.
- The Crawl stage emphasizes secure data sharing based on priority use cases.
- Privacy can be a challenge for large customers where aggregation thresholds can't be met; customer consent models or formal privacy frameworks may be solutions to these problems.
- Data sharing can range from manual processes, to automated data sharing, to APIs, to system-to-system integrations. Cost and complexity increase with more automation and integrations. Cost needs to be considered against value to ensure ratepayers are not overbuilding systems that do not result in positive impacts to affordability.

c. Southern California Edison

SCE reiterated its support and expressed strong alignments with the overall workshop objective of improving DER visibility and operational alignment at the T&D interface.

SCE emphasized that improving coordination across the T&D interface is foundational to addressing the challenges introduced by high DER penetration. The utility noted that increased DER adoption has led to greater variability in load and generation, requiring enhanced coordination to improve forecasting accuracy and situational awareness. SCE highlighted that strengthened coordination would enable more effective utilization of demand-side flexibility, improve system efficiency, and support affordability by reducing reliance on higher-cost operational interventions.

A central theme of SCE's presentation was the importance of a use-case-driven approach to data sharing and coordination. SCE stated that progress depends on clearly defining the operational problems to be addressed and identifying the specific data elements, aggregation levels, and timing requirements needed to support those use cases. SCE indicated that this level of specificity is necessary to evaluate system readiness, determine potential investment needs, and assess cost-effectiveness and customer value.

SCE further noted that discussions regarding data sharing and coordination remain at a conceptual stage and that additional technical development is needed before policy or investment decisions can be appropriately considered. SCE stated that any future investments in coordination capabilities would be subject to standard Commission review processes and should be supported by clearly defined requirements and demonstrated customer value.

To illustrate a potential implementation pathway, SCE presented a full-cycle coordination model describing a continuous, bidirectional exchange of information between the DSO and CAISO. Under this model, the DSO would provide to CAISO day-ahead forecasts, including aggregated net load and DER forecasted limits, as well as real-time estimates of available demand flexibility. CAISO would use this information to inform market clearing and dispatch decisions and would subsequently provide feedback to the DSO, including market schedules, dispatch outcomes, and operational data. The DSO would then reconcile post-market conditions and monitor distribution system performance.

SCE identified several categories of data that could support coordination, including day-ahead forecasts, real-time flexibility estimates, and distribution system events provided by the DSO, as well as market dispatch data and operational insights provided by CAISO. SCE indicated that these examples are illustrative of the types of data exchanges required to support coordination across planning and operational timeframes.

SCE also identified key challenges to implementing effective coordination, including the absence of standardized data models and exchange protocols, the need to align on timing and operational requirements, and the lack of clearly defined roles and responsibilities among CAISO, utilities, and other market participants. SCE emphasized that improved DER visibility alone is insufficient without defined coordination processes to translate data into operational actions.

Finally, SCE highlighted the ongoing work of the CAISO Coordination Framework Industry Expert Working Group as the appropriate forum for developing and prioritizing detailed use cases, addressing data gaps, and refining coordination approaches. SCE indicated that continued collaboration in this forum will be important to inform future policy considerations and support the development of a scalable coordination framework.

d. San Diego Gas and Electric

SDG&E organized its presentation into four sections covering an introduction with the SDG&E perspective and guiding principles, the current state, future plans, and data synergy and collaboration opportunities. SDG&E articulated five guiding principles for its work in this space: striving for customer-focused, reliability-driven data sharing; clearly defining the problems being addressed, the data requirements, and incrementally building on existing data-sharing foundations; pursuing DER visibility where necessary while ensuring compliance with privacy rules and grid cybersecurity; ensuring clear ratepayer value before scaling investments, given that infrastructure and IT costs must demonstrate tangible customer benefits and that a measured, incremental approach is prudent; and leveraging pilots and targeted initiatives to validate benefits before broad-scale deployment.

Turning to current state, SDG&E reported that it hosts approximately 3,282.8 megawatts of distribution-connected DERs, with the largest categories being NEM and NBT solar, NEM and NBT paired storage, standalone advanced energy storage, SDG&E Sustainable Community AES, SDG&E-owned AES, NEM wind, non-NEM solar, SDG&E Sustainable Community solar, SDG&E-owned solar, and WDAT resources. SDG&E currently shares data with CAISO via ICCP and has telemetry requirements for WDAT projects and Rule 21 projects greater than one megawatt. Behind-the-meter visibility is limited – required only for Rule 21 projects with a Point of Common Coupling greater than one megawatt – and AMI 1.0 cannot disaggregate DER output from total load. Enhanced visibility is therefore needed to support granularity, spatial awareness, and accurate power-flow modeling. SDG&E's current DER data flow to CAISO comprises DERs with telemetry – including large PV, large BESS sites, transmission-connected resources, and Rule 21 projects greater than one megawatt – flowing through SCADA and RIG's, generally with three-second polling to Gen Ops and E&FP systems. CAISO receives megawatt, megavolt-ampere reactive, kilovolt, state of charge, ramp rate, upper and lower limits, and other high-level data such as Breaker Status via RIG telemetry, and in addition, CAISO collects MV-90 data directly from CAISO meters. CAISO operates these market systems using ADS setpoints for five-minute dispatch and AGC setpoints for three-second direct control. SDG&E highlighted that telemetry and control capabilities differ significantly across resource types, with high-resolution visibility and control for front-of-the-meter DERs, while most behind-the-meter DERs remain neither directly observable nor dispatchable. SDG&E also noted that organizational and affiliate separation constraints limit direct visibility between distribution operations and market dispatch functions, which can create coordination and forecasting challenges.

Regarding future plans, SDG&E presented a Visibility, Management, and Control Roadmap layered from device-level integration – involving OEMs, virtual power plants, and EV fleets using IEEE 2030.5 and OpenADR – through a DERMS layer providing telemetry ingestion, DER registry, and dispatch coordination, through an Advanced Distribution Management Systems (ADMS) layer for feeder operations and state estimation, an Enterprise Data Platform for forecasting, analytics, and streaming data, and ultimately a CAISO interface providing aggregated visibility, schedules, and coordination. SDG&E's data visibility layers progress from selective device-level visibility for critical and utility-controlled DERs with real-time telemetry on the order of seconds, targeted for high-value grid services; through aggregated fleet visibility from aggregators and VPPs with five-to-fifteen-minute telemetry and market participation data, which SDG&E views as the primary scalable path for many DER programs; through feeder-level operational visibility using SCADA and ADMS state estimation for voltage, load, topology, and switching awareness; and finally through the customer and AMI layer for net load visibility into behind-the-meter solar, storage, and EVs, currently using AMI 1.0 with higher resolution anticipated upon AMI 2.0 deployment. Key future capabilities include SDG&E's planned Enterprise DERMS procurement in 2027, integration with the Distribution Interconnection Information System (DIIS) DER registry to synchronize GIS, DIIS, and ADMS data sources, weather telemetry, enhanced forecasting incorporating non-weather-based DER profiles for charging and discharging behavior, AMI 2.0 for higher-resolution data, and workshop-informed evaluation of potential CAISO data-sharing enhancements.

SDG&E identified three principal opportunities for collaboration with CAISO. The first is aligning on operational challenges, which requires clearly defining the specific operational challenges that enhanced DER visibility is intended to address and establishing shared priorities. The second is defining data needs and coordination mechanisms, using the identified challenges to inform the scope, granularity, and cadence of data exchange – for example, Wholesale Distribution Access Tarriff and VPP dispatch schedules sent back to IOUs – while also determining minimum viable data standards and clarifying roles across load-serving entities (LSEs), scheduling coordinators, aggregators, and third-party DER providers. The third is anchoring investments in customer value by ensuring investments deliver demonstrable customer and grid benefits, advancing incrementally through targeted pilots, and aligning investment pace and scope with framework maturity. SDG&E concluded by reaffirming its support for a value-driven approach to enhancing DER visibility, with investments that are cost-effective and customer-beneficial, and by committing to continued collaboration with CAISO, the Commission, and stakeholders.

e. Open Access Technology International Inc.

OATI walked through illustrative technology capabilities and architectural approaches for scalable, secure, and interoperable data-exchange ecosystems in a high-DER environment. OATI identified three principal benefits: improved coordination across aggregators, distribution operators, and grid operators; improved planning, situational awareness, and forecasting through standardized data flows; and enhanced market efficiency through scalable DER integration. To illustrate the coordination need in a high-

DER environment, OATI presented a stakeholder diagram showing data flows among community choice aggregators (CCAs), Load Serving Entities (LSEs), aggregators, utilities – including the DSO, ADMS, Enterprise DERMS, and Customer Information System (CIS) and Meter Data Management (MDM) systems – microgrids, large loads, prosumers, and CAISO market systems including forecasting and the Distributed Energy Resource Rating Service. The key data exchanges include enrollments, schedules, limits, curtailments, derations, outages, and opt-in and opt-out signals.

OATI drew a historical parallel to FERC Order 888/889 in the 1990s, which enabled transmission open access through tools such as OASIS, E-Tagging, the North American Electric Reliability Corporation (NERC) and North American Energy Standards Board (NAESB) Registry, and Interchange Distribution Calculator (IDC), Unscheduled Flow Mitigation Plan (UFMP), TLR, and locational marginal price (LMP)-based applications, and suggested that a similar standardization approach could enable DER orchestration. OATI's reference architecture comprises three layers. The infrastructure layer addresses scalability, performance, cybersecurity, and information privacy. The platform functions layer supports user management, workflow management, business rules, and transactional management. The applications layer addresses use cases, portals and APIs based on open standards, and operational workflows. Platform use cases identified include entity and resource registration, improved system planning, improved operational forecasting, operational coordination, and look-ahead situational awareness. Platform functions identified include data transformation, mapping, and aggregation; DER registry master data management; operating data management; orchestration and workflow management; data validation and business rules; a user interface portal; standards-based APIs; message exchange management; and user workspace management. OATI illustrated workflows for VPP registration in the pre-operation phase, day-ahead and real-time coordination in the operation phase, and metering and settlement in the post-operation phase, each defining roles and data exchanges among the DSO, aggregator, CCA or LSE, operations coordination platform, and CAISO.

Key considerations OATI identified include DER registry definition for both participating and non-participating resources; grid services coverage spanning CAISO market products and distribution operations; situational awareness and forecasting incorporating outages, derations, and granular net-load forecasts; topology and mapping including seams, sub-LAPs, and pricing nodes; the business process framework; tariff and regulatory considerations; and deployment strategy. OATI offered a phased deployment call to action. Phase I would focus on core capabilities including a DER Registry 1.0, DSO-CAISO operational coordination for market participation, and net-load forecasting at T&D seams. Requirements specification would take six to nine months involving straw requirements and stakeholder workshops for review, refinement, and approval. System development would take twelve months for cloud-based software-as-a-service implementation, systems integration, training, and support. Testing and verification would take three months, followed by statewide rollout.

f. Piclo

Piclo presented its flexibility marketplace model as a mechanism to enable DER participation in grid services, positioning the platform as a neutral intermediary that connects utilities and system operators with DER providers through a standardized procurement and settlement framework. The platform's core function is needs-based flexibility procurement, in which utilities and independent system operators publish specific system needs—such as location, capacity (MW), and timing—rather than prescribing particular technologies. This approach is intended to broaden participation by allowing a diverse set of DERs to respond to identified needs, thereby revealing previously untapped or "hidden" flexibility.

Effective marketplace operation requires access to granular, asset-level data and forward-looking availability information. Piclo emphasized that centralized, multi-purpose DER registries can present implementation risks if they are not tied to a clearly defined use case and supported by participant incentives to maintain data accuracy. Real-world experience demonstrates that registry systems lacking a clear purpose or incentive structure have, in some cases, failed to deliver value due to outdated or incomplete data. Accordingly, incentive-driven participation—such as providing access to revenue opportunities—is critical to ensuring data quality and ongoing system reliability.

From an architectural perspective, the platform is designed to function as a neutral connector rather than an aggregator, facilitating integration between utility systems and DER providers while supporting an end-to-end workflow that includes registration, procurement, dispatch, and settlement. The platform can be deployed incrementally, beginning with simpler tools and processes and evolving over time toward fully integrated, API-enabled systems.

Piclo also outlined a typical progression of use cases for flexibility markets. Initial applications often focus on long-term needs such as non-wires alternatives for capacity deferral, followed by mid-term forward procurement mechanisms, and ultimately shorter-term day-ahead and intraday operational markets. The presentation noted that the greatest system value is realized as markets evolve toward more operationally integrated use cases that align closely with real-time system needs.

The ability to support value stacking—allowing DERs to participate in multiple programs or revenue streams—was identified as a key requirement for achieving economic viability and scale. Marketplace platforms can play a role in enabling such participation while also providing coordination and monitoring capabilities to mitigate risks such as double counting of services.

A case study from the United Kingdom illustrated the coordination of TSO and DSO needs through a national-scale implementation. This approach uses locational capacity limits, or "envelopes," to ensure that DER dispatch remains within distribution system constraints. The model represents a pragmatic and scalable approach that relies on simplified assumptions in its current form, with a planned evolution toward more dynamic, real-time coordination.

Finally, several implementation considerations were highlighted. These include the importance of starting with near-term, actionable use cases—such as improving procurement efficiency—rather than attempting to design a fully optimized end state at the outset; the need for clear, long-term policy and utility commitment signals to support DER investment and participation; the value of building operational confidence through real-world deployment and performance data; and the necessity of addressing both technical integration challenges and institutional coordination issues, including structural differences between U.S. and international program frameworks.

g. Open Discussion: Developing an Operation TSO-DSO Coordination Framework

During this open discussion, multiple stakeholders had a broad, collaborative discussion on how various stakeholders can work together to develop an operational TSO-DSO coordination framework. The discussion highlighted several interrelated challenges affecting DSOs, particularly regarding data access, forecasting, and coordination.

At present, DSOs lack sufficient visibility into critical datasets needed to accurately forecast conditions at the T&D interface. Key gaps include (1) no access to LSE load forecasts, (2) no data on DERs participating in non-IOU programs, such as status, availability, schedules and dispatches, and (3) no data on third-party DER participating directly in the ISO wholesale market, such as status, availability, schedules and dispatch. As a result, DSOs operate with an incomplete view of system conditions, which constrains both forecasting accuracy and real-time operational awareness.

Addressing these visibility limitations would likely require expanding data-sharing obligations across entities. In particular, stakeholders noted the potential need for LSEs to transmit load forecasts to IOUs, as well as the possibility of providing access to more granular inputs such as day-ahead market bids or disaggregated forecast data. However, these proposals raise important feasibility and policy considerations, including whether regulators should mandate additional data exchange requirements and how such requirements would be implemented.

A related issue is the lack of sufficient insight into demand flexibility (DFlex). DSOs require more than static load forecasts; they need a clearer understanding of the operational capabilities and constraints of DERs. Without this, it is difficult to assess how flexible resources can respond under different system conditions. Stakeholders suggested that more advanced analytical approaches, such as operational studies, could help quantify uncertainty and better characterize DER performance.

On the TSO side, the CAISO receives LSE demand forecasts at a higher aggregation level in day-ahead timeframe. Real-time demand forecasts are not generated by LSEs. The CAISO will generate real-time demand forecasts that are utilized in the market optimization. The CAISO faces similar issues with visibility into utility rates and demand-side DER programs. Data visibility should go in both directions between the CAISO and DSOs. DER loads are non-conforming loads that behave less predictably than conforming loads, such as street lighting and behind-the-meter solar, because their operation depends on human behavior and external drivers rather than consistent patterns, making them harder to forecast. Improving information sharing across system operators is especially important for managing non-conforming loads. To better understand and coordinate unpredictable, non-conforming resources, the CAISO needs greater visibility into more granular local data that DSOs have access to. Coordination between the TSO and DSOs is essential to addressing the gaps both entities have identified.

Forecasting itself was described as inherently complex, as it involves not only estimating expected demand but also accounting for the uncertainty associated with that demand. Variability driven by factors such as weather further complicates this task. As a result, effective coordination depends on richer and more sophisticated datasets, including probabilistic forecasts and information reflecting DER-driven variability, rather than relying solely on traditional demand forecasts.

In terms of coordination, some participants suggested narrowing the focus to the interface between TSOs and DSOs as a way to simplify data requirements and coordination challenges. At the same time, there was broad recognition that fragmented, utility-specific approaches are insufficient. Stakeholders emphasized the need for a more integrated, statewide framework to ensure consistent and effective coordination across entities.

Finally, the discussion underscored several principles for implementation and next steps. Participants emphasized the importance of prioritizing use cases that deliver clear operational value and pursuing incremental, near-term actions while planning for more advanced long-term capabilities. Information exchange was identified as a foundational requirement across all stakeholders. Additionally, working groups and collaborative stakeholder processes were seen as critical mechanisms for scaling successful approaches and aligning efforts across the system.

h. Open Discussion: Aligning on DER Modeling and Forecasting Integration

In the second open discussion, stakeholders discussed how the CAISO, the IOUs, and other entities can better align forecasting methods and DER modeling. Several themes emerged from the discussion.

First, stakeholders discussed existing opportunities to improve real-time visibility and clarity of DER activity and load impacts between DSOs and the TSO using existing telemetry. One incremental proposal was that DSOs could provide a simple, aggregated analog signal from CAISO to represent total dispatch across all resources in a DSO territory, while DSOs send aggregated behind-the-meter generation data using existing remote intelligent gateways.

Second, stakeholders discussed clarifying the DSOs' role and responsibilities beyond the traditional role of an IOU as a fundamental step in addressing gaps in forecasting integration and DER modeling. The discussion highlighted that the information flow and visibility that is foundational to forecasting and DER modeling requires clear roles, transparent communication, and trust-building with IOUs, aggregators, CCAs, and other stakeholders. Stakeholders also highlighted that progress should focus on identifying specific gaps in forecasting, testing targeted information flows to address those gaps, and then prioritizing solutions that best resolve those gaps.

Third, stakeholders discussed the need for continuing collaboration in developing DER Orchestration potentially through regular CPUC-led workshops or working groups to share progress, refine coordination framework, and compare use cases. Stakeholders also stressed the importance of explicitly linking DER integration efforts to tangible reliability and affordability benefits.

V. Conclusion

The workshop discussion highlighted agreement across participants that there are significant visibility and data sharing gaps that need to be addressed through improved TSO-DSO coordination. There was general agreement that the Operational Coordination Framework is an important component of enhancing coordination and improving DER integration. The workshop discussion also identified the need to further discuss and explore how to move on to the next steps of developing and implementing a Coordination Framework. Additionally, the discussion identified the value of continued transparency on progress made on the Coordination Framework.

The High DER proceeding was opened to address the challenges associated with DER integration and to create a regulatory landscape that allows for the expanded proliferation of DERs that captures the full reliability and affordability benefits of DERs, and this workshop reflected the continued effort to comprehensively evaluate the information available and identify and address gaps at the transmission and distribution system interface level.

Looking ahead, participants broadly recognized that improved TSO-DSO coordination has the potential to deliver multiple categories of value. These include strengthening electric system reliability through enhanced situational awareness and operational coordination, improving affordability through more efficient forecasting and market outcomes, and enabling greater utilization of demand flexibility resources to meet future system needs. Participants generally agreed that the increasing scale and complexity of DER adoption creates urgency for developing coordination mechanisms that can support these objectives.

DER Orchestration Workshop 2: Developing a TSO-DSO Coordination Framework

High DER Proceeding (R.21-06-017) Track II

CPUC Energy Division

June 5th, 2026

California Public Utilities Commission

Safety Announcements

- **In Case of Emergency:**
  - Listen for alams/PA announcements; CAISO staff will receive alerts and coordinate via radio
  - Security guards are first aid/AED trained
- **Evacuation Instructions:**
  - Primary Route: Exit meeting space, head through lobby and out the doors to the visitors' parking lot, Zone B (right)
  - Alternate Route (if blocked): Stairs to ground floor, exit through exits near café, follow fire road to Zone C
  - Follow Floor Wardens (orange vests) and remain at zone until all-clear signal
- **Safety Equipment:**
  - A fire extinguisher is located just outside the conference room
  - First aid kits are available at the security desk in 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 (include your org name on Webex icon)
  - Try not to repeat points that have already been made, and 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 may type questions/comments in the 'chat' to be read aloud during Q&A.  
    - When your question is addressed you may raise your hand to ask yourself and/or follow up for clarification.

Opening Remarks

Commissioner Darcie L. Houck & CEC Vice Chair Siva Gunda

Agenda

Time	Party/Agenda Item
10:00am-10:15am *(15 min)*	**CPUC:** Introduction, Safety, Logistics, Opening Remarks
10:15am-10:30am *(15 min)*	**ED:** Background, Workshop Objectives, Framing, and Key Discussion Topics
10:30am-11:30am *(1hr)*	**CAISO:** Operational and Forecasting Challenges, Level-Setting, TSO DER Visibility Needs, Q&A
11:30am-12:30pm *(1hr)*	**IOUs (PG&E, SCE, SDG&E):** DSO DER Data Sharing Capabilities, TSO-DSO Coordination Gaps, Q&A
12:30pm-1:30pm *(1hr)* *(30 min tour included)*	**Lunch** + Operations Room Tour (optional)
1:30pm-2:00pm *(30 min)*	**Open Access Technology International (OATI):** Presentation + Q&A
2:00pm-2:30pm *(30 min)*	**Piclo:** Presentation + Q&A
2:30pm-3:15pm *(45 min)*	**Open Discussion:** TSO-DSO Coordination Framework Development
3:15pm-3:45pm *(30 min)*	**Open Discussion:** Forecasting Integration and DER Modeling Alignment
3:45pm-4:00pm *(15 min)*	**CPUC**: Wrap-up and Next Steps

Background

Energy Division Staff

High DER Track II: Background & Procedural History

- The CPUC’s High DER Proceeding (R.21-06-017) aims to modernize California’s electric distribution grid and planning processes so the system can reliably, equitably, and efficiently support a high level of distributed energy resources (DERs)
- Track 2 of the High DER Proceeding aims to develop a framework for DER Orchestration with Investor-Owned Utility's (IOUs) acting as Distribution System Operators (DSOs)
- The Future Grid Study (FGS) Report, published by Gridworks in 2024, outlined operational needs, capability gaps, and recommendations for a high-DER future grid. The operational needs identified in FGS formed the initial foundation for the 'DER Orchestration' framework being developed under Track 2.

Overview of DER Orchestration & TSO-DSO Coordination

- **DER Orchestration** is the coordinated management of DERs by a DSO to identify location-specific and time-specific distribution needs and signal DERs to deliver verifiable services that align with those needs.
  - It enables DERs such as including solar, batteries, electric vehicles, and flexible loads to provide measurable distribution-level services to support grid reliability, constraint management, and grid optimization.

- **TSO-DSO Coordination** relies on enhanced data sharing, forecasting, and operational coordination to align transmission and distribution system DER operations.
  - As DER adoption grows, transmission system operators (TSOs) have limited visibility into many demand-side resources, including behind-the-meter batteries, electric vehicles, and flexible loads.
  - Improved visibility into DERs is critical for accurate load forecasting, grid reliability and efficient TSO operations.

Workshop Objectives & Key Topics

Energy Division Staff

TSO-DSO Coordination Workshop Objectives

1. **Enhance** CAISO DER Visibility by improving access to aggregated data on DER capacity, schedules, and performance to support accurate forecasting, market efficiency, system reliability.
2. **Strengthen** TSO-DSO coordination by clarifying roles, responsibilities, and data-sharing protocols, so that DERMS development aligns with CAISO's operational needs.
3. **Align** TSOs, DSOs, and other participating entities on shared priorities for DER integration and grid operations in a high DER future.

Workshop Key Topics

The TSO-DSO Coordination Workshop aims to meet the previously stated objectives by inviting stakeholders to present on the following key topics:

1. **CAISO:** Operational and Forecasting Challenges, Level-Setting, and TSO DER Visibility Needs
2. **IOUs/DSOs:** DER Data Sharing Capabilities
3. **OATI & Piclo:** Centralized Data Exchange and Technology Platform Considerations
4. **Open Discussion:** Developing an Operational TSO-DSO Coordination Framework
5. **Open Discussion:** Forecasting Integration and DER Modeling Alignment
6. **Closing:** Next Steps, Workshop Report and Ongoing Collaboration

CAISO: Operational and Forecasting Challenges, Level-Setting, and TSO DER Visibility Needs

- **Level-Setting on DER Visibility and Identification Needs**
  - Usings DER participation pathways to enhance both CAISO visibility into demand-side DERs and DSO visibility into supply-side DERs
  - Specific DER visibility and data needs requiring coordination with participating entities

- **Operational and Forecasting Challenges**
  - Operational planning and forecasting challenges due to the limited DER visibility of the total installed capacity and geographic distribution of demand-side DERs
  - Operational issues associated with enabling supply-side distribution-level DER services

- **Operational Coordination Framework Development**
  - Framework developments and joint efforts to enhance DER information & visibility, operational forecasting, and operational coordination

IOUs/DSOs: DER Data Sharing Capabilities

- Discuss how respective IOU development/deployment timelines to enable enterprise and grid-edge DERMS can be aligned with the CAISO's operational needs

- Discuss additional data sharing capabilities, opportunities for TSO-DSO coordination, data exchanges, technical/ privacy constraints, and remaining gaps requiring further coordination

OATI & Piclo: Centralized Data Exchange and Technology Platform Considerations

- Technology platforms that exhange data in an automated, centralized way may be one way to help bridge gaps in operational coordination
- Open Access Technology Incorporated (OATI) and Piclo are examples of providers of these types of technology platforms
- Representatives from OATI and Piclo have been invited to discuss data exchange considerations and illustrate potential solution pathways to bridging TSO-DSO coordination gaps

Open Discussion: Developing an Operational TSO-DSO Coordination Framework

- Discuss the need for multi-directional data flow between all participating entities including CCAs, aggregators, and third-party DER providers
- Discuss ways in which coordination frameworks can support both bulk electric system grid services and distribution level services while prioritizing reliability
- Identify further development needed to integrate data from multiple providers of demand-side flexible DER
- Identify coordination areas to focus on where DERs serve both systems - registration and dispatch protocols
  - For example, discuss areas of coordination needed to reduce the risk of conflicting DER dispatch commitments across system levels
- Discuss how the operational requirements for DSOs grid services and CAISO wholesale market participation can form distinct pathways

Open Discussion: Forecasting Integration and DER Modeling Alignment

- Develop a shared understanding of the roles of CAISO, DSOs, LSEs, Scheduling Coordinators, and Aggregators, and ways to further develop or define these roles
- Assess information exchange systems and identify gaps between entities in forecasting alignment priorities

Operational Coordination at the Transmission-Distribution Interface

California ISO - Kevin Head

COORDINATION AT THE TRANSMISSION-DISTRIBUTION INTERFACE

CPUC High DER Future Proceeding – Track 2 Workshop

California Independent System Operator

June 5, 2026

Structure of presentation

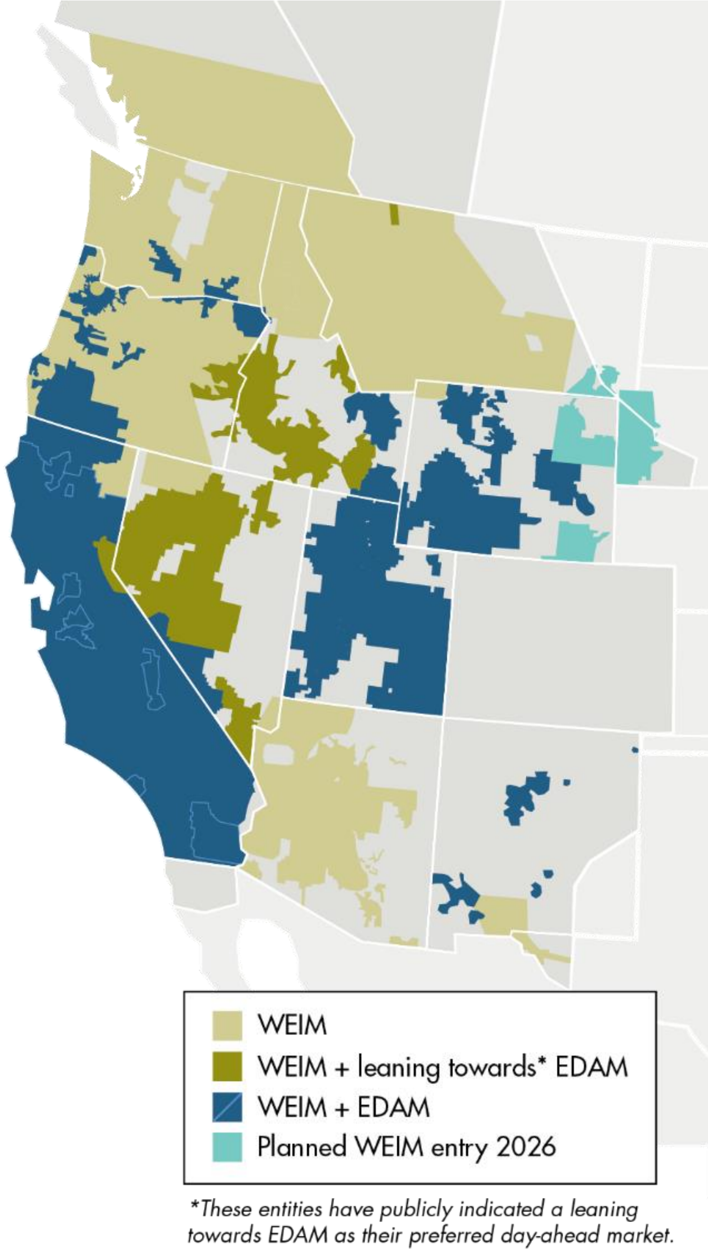
1. Level-setting and need identification	DERs affect transmission and distribution operations, increasing the need for greater coordination between CAISO, utilities, and others
2. Current status and gap assessment	Coordination activities exist today but can be enhanced to resolve gaps
3. Operational and market challenges	Gaps in operational coordination can create operational and market challenges
4. Operational coordination framework	CAISO is partnering with others to develop an operational coordination framework that we expect can help bridge these gaps

LEVEL-SETTING AND NEED IDENTIFICATION

Landscape

- Growing electricity demand, increasing extreme weather, and the rapid expansion of diverse set of distributed energy resources (often non-market DERs) are reshaping system operations, creating new coordination challenges and making improved visibility and alignment across the T&D interface more critical than ever.

- Regional markets like EDAM and WEIM create new opportunities to capture and scale that flexibility, if it is measurable, visible and coordinated.



CAISO Visibility: Supply Side and Demand Side

Supply Side

Distributed Energy Resource (DER) Aggregation: Aggregation of bidirectional DERs into one resource; min 100 kW

Reliability Demand Response Resource (RDRR): "Emergency DR" Triggered only under certain emergency conditions; min 500 kW

Proxy Demand Response (PDR): "Economic DR": Enables utilities or 3rd parties to bid demand response into the CAISO market; min 100 kW

In Front of the Meter Market Models: *Ex: Non-Generator Resource, Participating Generator, Eligible Intermittent Resource, etc.*

Visible to CAISO

Emergency

Incremental & emergency load-flexibility programs

Limited Visibility for DO

Load Modifying

Utility Rates

Utility Programs: DERs that participate in utility programs not integrated into the CAISO market

Limited/Lack of Visibility for CAISO

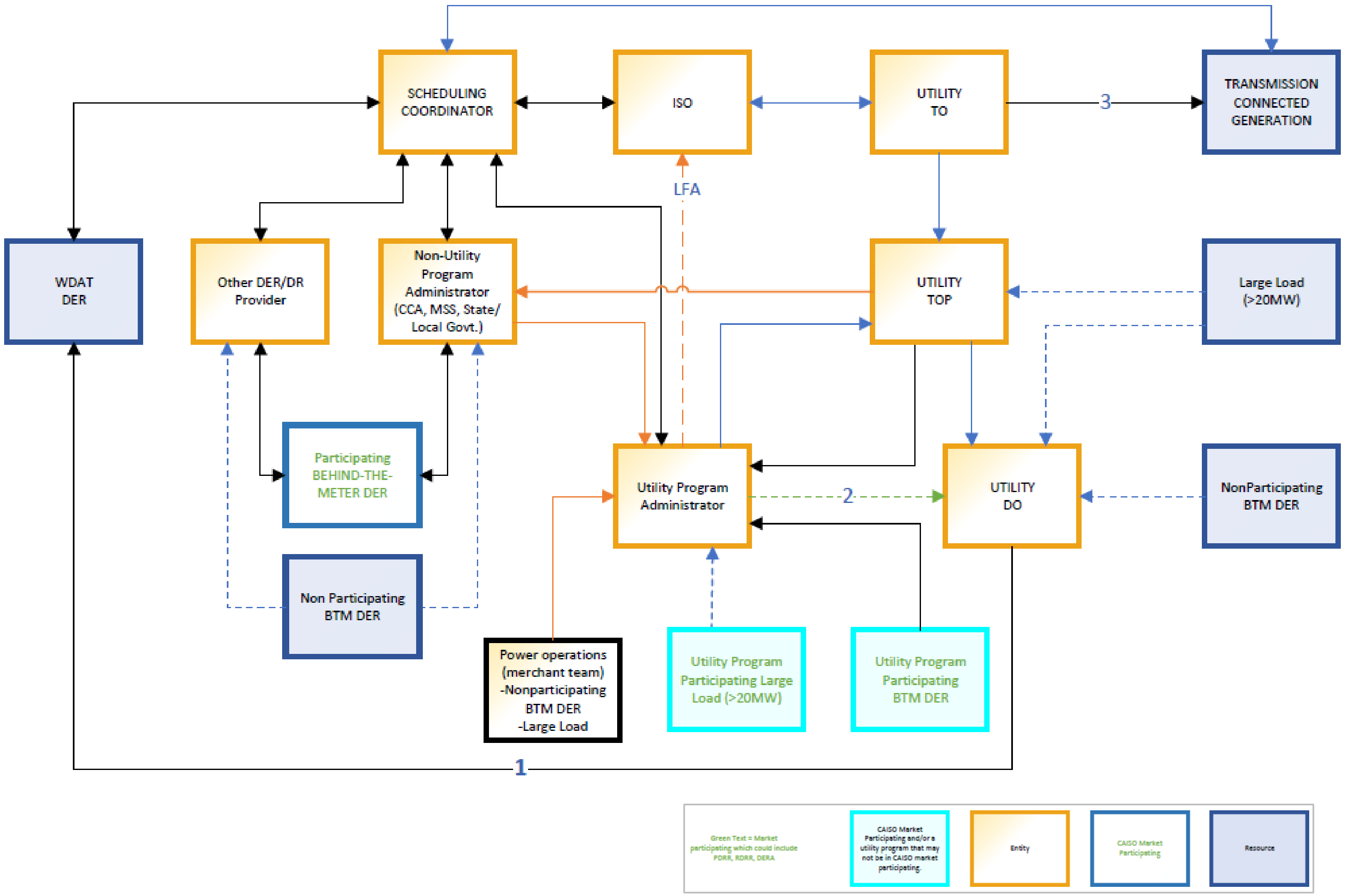
CURRENT STATUS AND GAPS ASSESSMENT

Who’s Who

Roles and responsibilities in current operational coordination

Role	Responsibilities
CAISO (ISO)	• Operates the wholesale market and maintains reliability of the bulk electric system, incl. frequency response, balancing supply and demand, and voltage management within its operational control.
Scheduling Coordinator	• Interfaces with CAISO markets by submitting bids/offers, representing resource availability, receiving dispatch instructions, and coordinating schedules with the ISO.
Other Demand Response or DER Provider	• Aggregates and represents demand response resources participating directly in CAISO markets (e.g., PDR), enabling load reductions to be dispatched as supply.
Non-Utility Program Administrator	• Manage customer load and retail programs without owning transmission or distribution assets; shape load through rates, programs, and DER offerings. Examples include Energy Service Providers (ESPs) and Community Choice Aggregators (CCAs).
Utility Program Administrator	• Utility-administered demand response programs, which may participate in markets or operate for reliability and local grid needs.
Utility Transmission Owner (TO)	• Owns and plans transmission infrastructure
Utility Transmission Operator (TOP)	• Coordinates with CAISO to ensure reliable operation of the transmission system.
Utility Distribution Operator (DO)	• Owns, plans, and operates distribution infrastructure

Transmission–Distribution coordination today (DRAFT)



- This flowchart is a first-draft attempt to characterize the various interactions and data flows between the various entities involved in T&D coordination
- The development of this graphic is still in-progress, so may not reflect actual current state and does not reflect an ideal future state
- CAISO includes this graphic to illustrate some data flows that currently exist, as well as the complexity inherent in T&D coordination

Current Operating Reality

- Data flows are fragmented:
  - Many data exchanges are in development or rely on non-automated methods.
- Aggregation mismatches
  - Modeling granularity differs across the ISO/TO/DO boundary
  - Inconsistent aggregation levels
- Limited operational time frame awareness
  - Distribution operators have limited visibility into ISO actions
  - CAISO has limited visibility into distribution-side actions.

Summary: Coordination Framework Gaps

- The grid is evolving faster than the operational frameworks that support it.
- Across all four dimensions – roles, visibility, forecasting, and coordination – one issue continually presents:

DERs influence both transmission and distribution operations. There are opportunities to advance the systems, responsibilities, and data pathways needed to manage transmission and distribution operations to ensure completeness, consistency, and definition.

- Closing these gaps is essential to:
  - Ensure reliability as DER penetration accelerates and system flexibility increases
  - Reduce operational uncertainty and associated costs
  - Enable safe, predictable integration of future flexible resources
  - Strengthen coordination across T&D operators

Deep Dive into Gap Findings

Roles and Responsibilities	Need to clarify ownership and alignment of roles and responsibilities regarding DERs
Information and Visibility	Forecasting and operations lack consistent data sharing on DER behavior
Operational Forecasting	Need to enhance forecasts capture DER impacts
Operational Coordination	Operational practices across ISO, TO, and DO need to align with current/future DER reality

Illustrative data gaps identified that may be addressed by sharing of existing data

Gap 1: Aggregated customer program and/or rate information to ISO

Use: ISO could utilize the information to improve short term demand forecasting

Gap 2: Aggregated installed DER information to ISO

Use: ISO could utilize the information to improve short term demand forecasting

Gap 3: Market-participating DERs' operating limits to ISO

Use: ISO could prevent large movements of demand that cause frequency issues

Gap 4: Resource specific outage/derates to ISO

Use: ISO could better reflect that resource in modeling and market optimization

Gap 5: Current system topology/modeling condition information to the ISO

Use: ISO would know the resource availability during changing operational topology/modeling conditions.

Gap 6: Schedule changes associated with large load operating limits, outages, de-rates to ISO

Use: ISO could incorporate into short term demand forecast and operational coordination activities

Gap 7: Capacities of operationally significant large loads along with their effective operating profile to ISO

Use: ISO could incorporate these into demand forecasts which could result in increased day-ahead forecast accuracy

Gap 8: Operationally significant large load day-ahead schedules, associated operating limits, and prior day's large load actuals to ISO

Use: ISO could incorporate these into demand forecasts which could result in increased real-time forecast accuracy.

Note: this list is not exhaustive, does not reflect the highest priority gaps, and isn't ranked in order of priority. Instead, they represent low-hanging fruit items that may be able to be addressed using existing data. Privacy and confidentiality issues may also require assessment before this data is shared.

OPERATIONAL AND MARKET CHALLENGES

CAISO has observed several distinct operational and market challenges that it believes can be addressed through better operational coordination

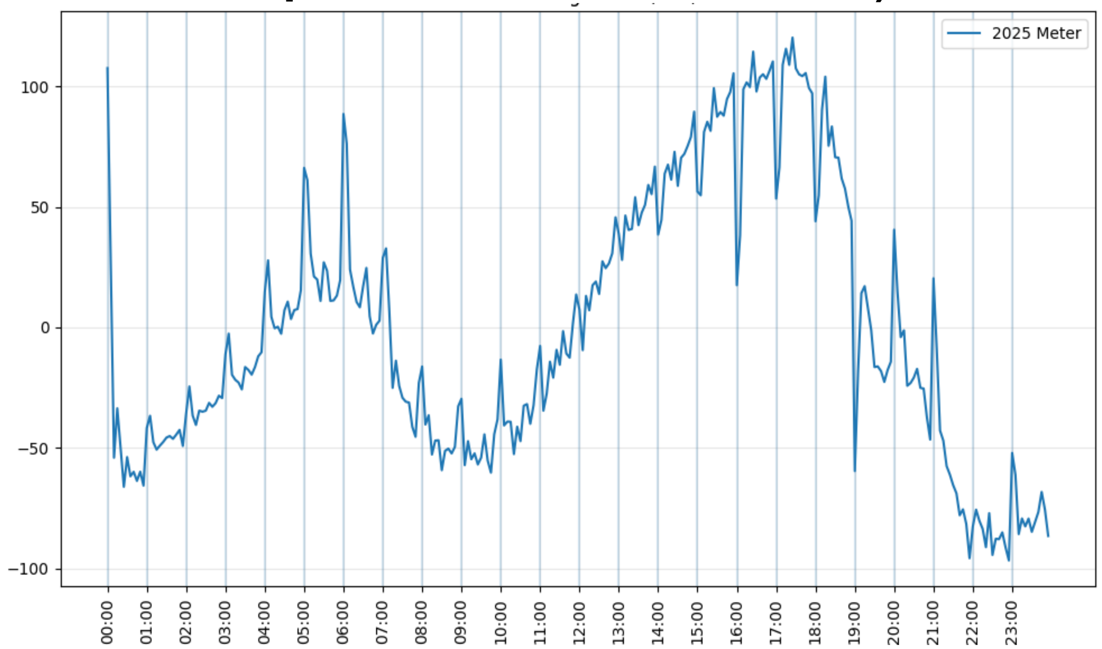
- Sudden and distinct changes in load levels occurring at the top-of-the hour
  - These may originate from DER responses to changes in Time of Use rates, particularly DERs that respond automatically

- Negative loads at certain substations, indicating that the distribution system is feeding back power to the transmission system
  - These may result from distribution-connected generation and storage facilities exporting such that they exceed nearby loads

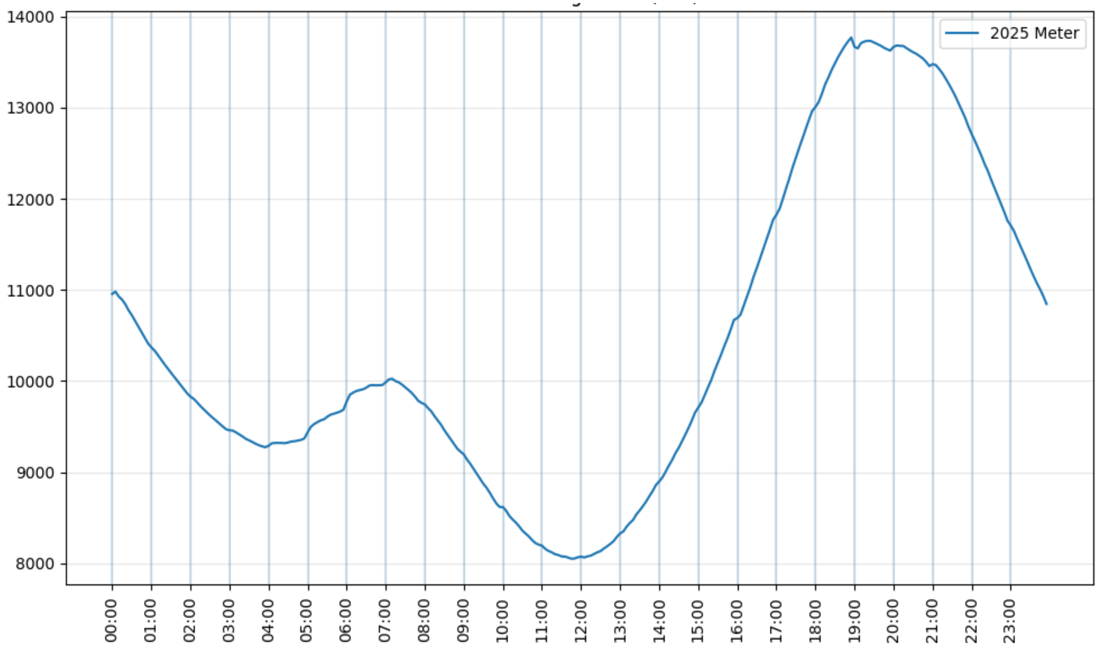
- Resources and loads can be modeled inconsistently between the CAISO and the utilities

CAISO has observed persistent top-of-hour demand movement throughout 2025

Average change in an area embedded within the CAISO system load (compared to previous 5-minute interval)



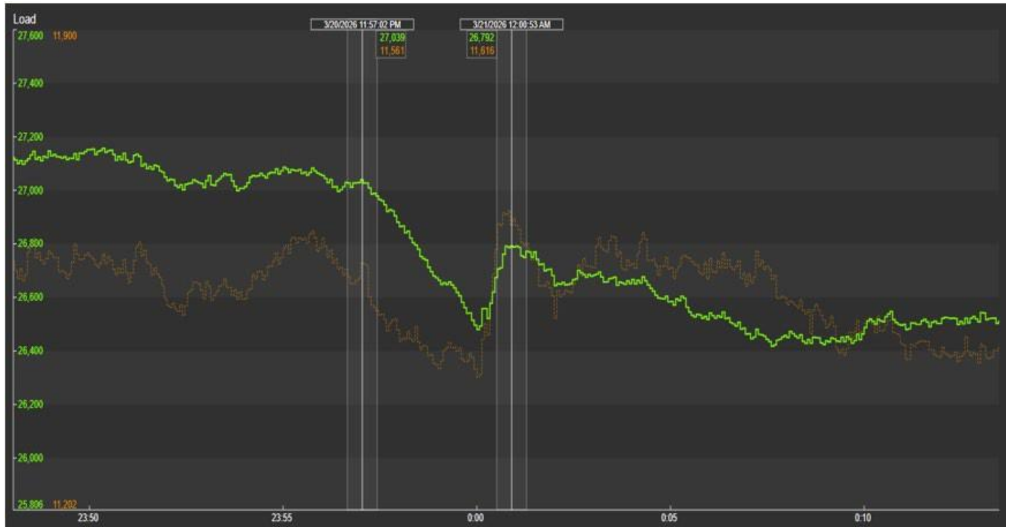
Average 2025 load in IOU area



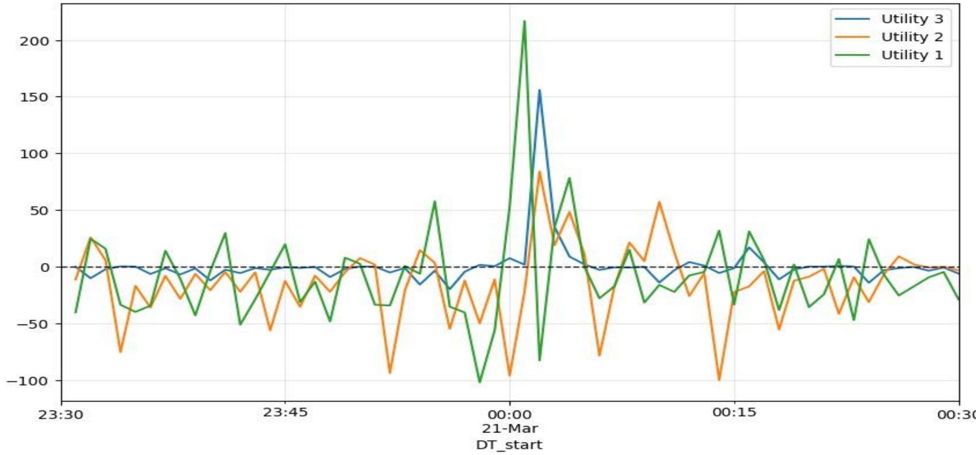
Midnight demand movements can be particularly pronounced

- 312 MW System-wide movement in 3/21/2026 00:00-00:01 timeframe.
- ~200 MW of movement during this timeframe was tracked to one area within the CAISO BAA.
- This amount of movement has been observed previously.
  - Up to 300 MW of movement during midnight timeframe in high movement days in single area of the CAISO BAA.
- Midnight jumps are not unique to CAISO BAA and span many western BAA entities.

CAISO system load* - 3/20/2026-3/21/2026 (1-sec interval)



Change in load by utility^ 3/20/2026-3/21/2026 (compared to previous 1-minute interval)



* Load includes market participating battery charging and discretionary pumps.
^ Load does NOT market include battery charging or discretionary pumps.

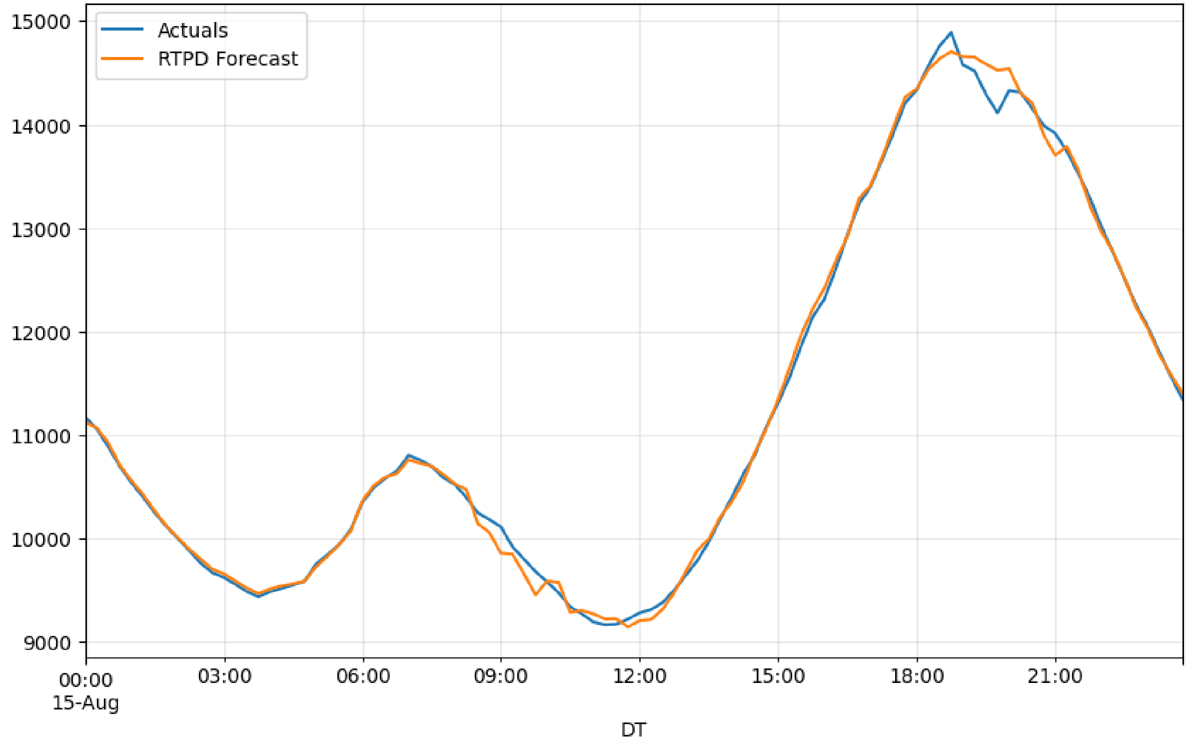
Top-of-hour demand movements can affect operations and market outcomes

- Top-of-hour demand movements can:
  - Decrease day-ahead/real-time demand forecast accuracy
  - Increase forecast uncertainty

- This causes potential operational impacts:
  - Higher momentary Area Control Error and frequency changes
  - Increased reliance on manual operator interventions

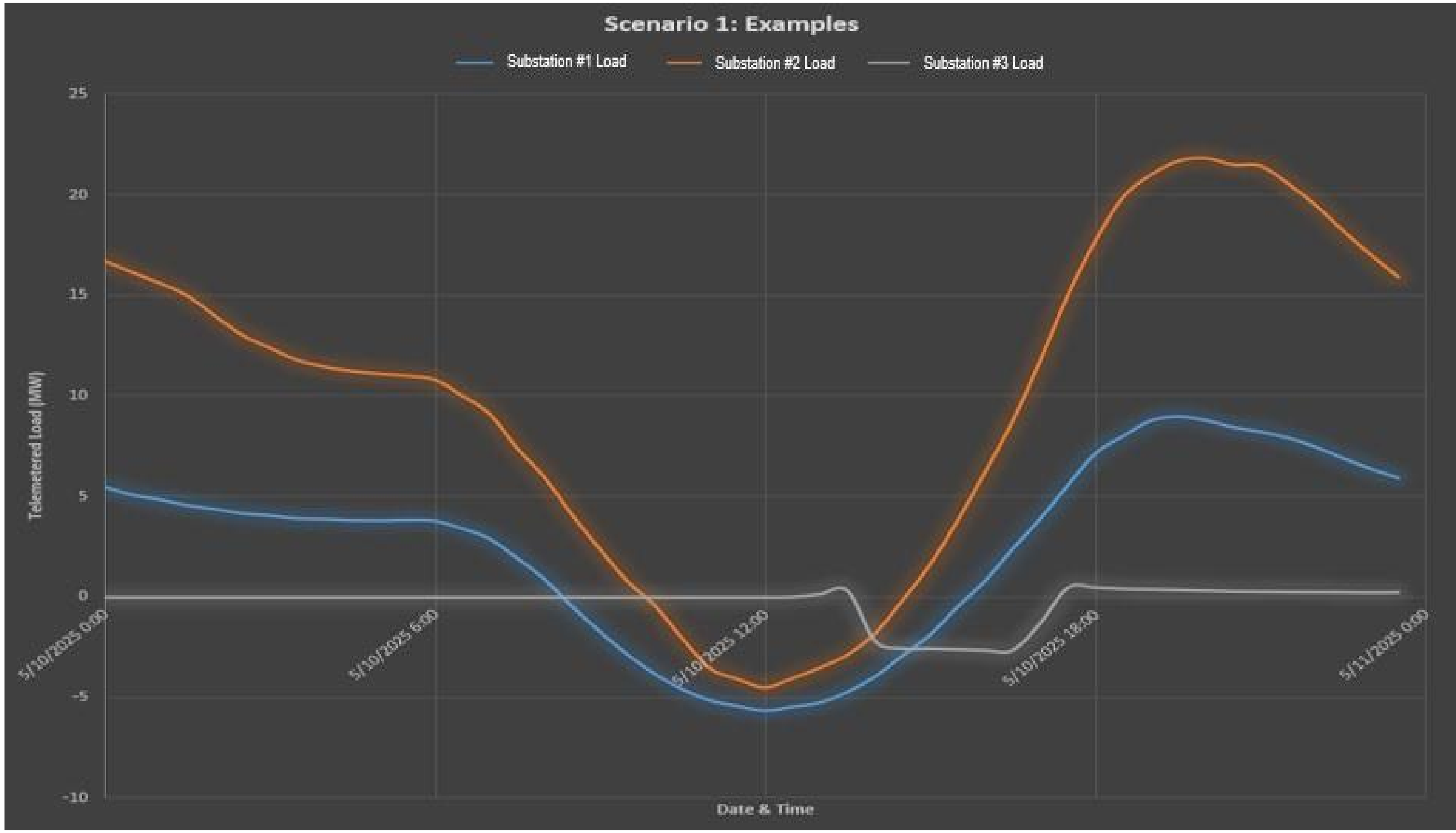
- It can also impact market outcomes:
  - Increased need to procure regulation and imbalance reserves
  - Impacted the Load Distribution Factors used in market optimization

Actual load vs 15-minute market forecast (August 15, 2025)



CAISO has increasingly observed negative loads (i.e. backfeed) from the distribution system to the transmission system)

- Similar to top-of-hour load changes, unstudied negative loads impact operational and market outcomes:
  - Can create overloads in areas that have not been studied for backflow
  - Can create congestion on the transmission system that is difficult to manage
  - Impacts the Load Distribution Factors used to allocate load forecast to specific areas, creating challenges in the market optimization



Inconsistent modeling and data collection practices impact information and visibility for operational forecasting, monitoring and study processes.

		Has contract(s) with interconnection customer?		Have modeling & operating data for resource/ load?			Have data for day ahead planning?			Have data for real time monitoring?		
	Examples of Issues	ISO	Utility	ISO	Utility Transmission	Utility Distribution	ISO	Utility Transmission	Utility Distribution	ISO	Utility Transmission	Utility Distribution
Market Participating resources	Utility distribution and transmission real time monitoring and outage management processes are impacted by flows from market participating energy and demand resources.	Yes	Yes	Yes	Varies	Varies	Yes			Yes	Yes – Bulk Electric System (BES) connected	Yes - Dist connected
Out-of-market resources	ISO operational forecasting, real time monitoring and assessment tools and processes are impacted by out-of-market energy and demand resources (e.g., Rule 21 Non Export, NEM, utility DR)		Yes		Yes - BES connected	Yes - Dist connected		Varies	Varies		Varies	Varies
Other resources	Utility distribution and transmission systems and ISO processes are impacted by flows from unknown energy, demand and load-modifying resources managed by non-IOU entities.		Varies		Varies	Varies		Varies	Varies		Varies	Varies
Load	ISO does not have a consistent process for modeling load and maintaining over time.		Yes		Yes - BES connected	Yes - Dist connected	Varies	Varies	Varies	Varies	Yes - BES connected	Yes - Dist connected

OPERATIONAL COORDINATION FRAMEWORK

Vision & Pillars

Vision

A future where demand flexibility is reliably and economically integrated into grid operations and market optimization

Coordination Framework

Strengthens coordination and situational awareness for market and non-market demand and supply by enhancing data visibility and forecasting capabilities.

Technology & Data Exchange

Define and develop the technology and data exchange requirements necessary to support the Coordination Framework with automated exchange of a common set of information.

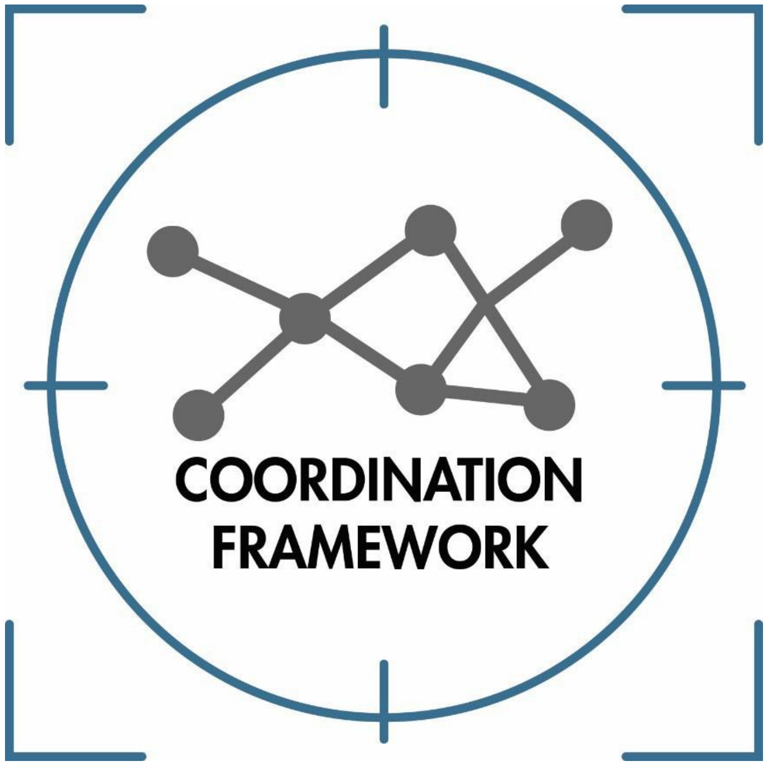
Market Design

Develops and enhances pathways to market access – both on the supply and demand-side

Policy & Regulatory Alignment

Collaborates with regulatory partners to identify and address barriers

Focus areas of coordination framework



- Enhanced Operational Coordination
- Information and Visibility
- Operational Forecasting

Business and reliability impacts of inadequate operational coordination

Reliability

- Increased operational uncertainty
- Reduced ability to proactively manage distribution and transmission constraints
- Higher risk of last-minute operator intervention

Affordability

- Increased reserve procurement driven by forecast uncertainty
- Inefficient market dispatch due to incomplete DER and demand visibility
- Deferred or missed utilization of lower-cost DER and demand flexibility resources

Strategic

- Demand Flexibility potential remains under-captured
- Fragmented program structures constrain customers ability to unlock the full economic value of DER investments

From challenges to future opportunities

ACTIONS

Enhance DER Visibility

- Improve forecasting to reduce uncertainty in market operations
- Strengthen situational awareness
- Integrate DER data into system planning

Leverage DER Dispatch Data

- Use dispatch information to improve emergency response and coordination
- Optimize market performance by aligning DER operations with system needs

Capture Incremental Demand Flexibility

- Enable new resources (large loads) and new sources of value
- Enhance reliability while reducing costs through flexible load participation
- Defer or avoid costly infrastructure investments by substituting DER flexibility for new build-outs

RESULTS

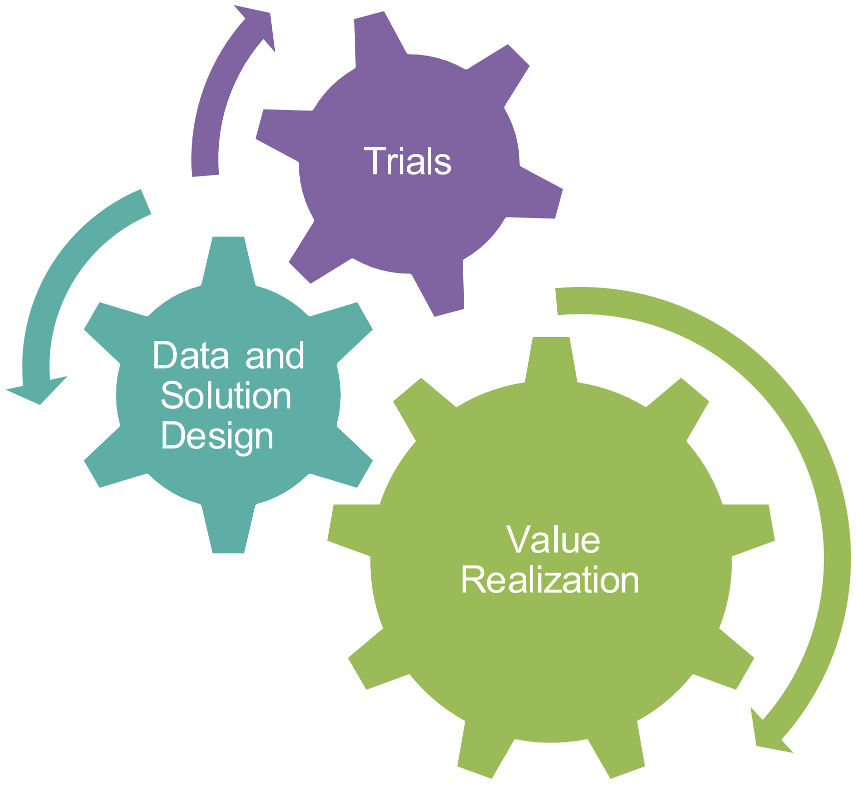
Reduce Uncertainty and Strengthen Reliability

Optimize Coordination and Market Outcomes

Enable Market Value and Defer Infrastructure

The Coordination Framework 2026 approach and deliverables

Customer-side resources are growing quickly, but the grid lacks consistent visibility and coordination impacting reliability and potential market outcomes.



2026	Documented Current Processes and Known Gaps
	Mapping of Information Exchange
	Future solution design for data exchange in standardized formats
2026-2030	Phased implementation of forecasting and operational improvements that reduce cost and increase reliability

Expert Working Group

- The Industry Expert Work Group (EWG) is a collaborative forum of diverse industry representatives focused on developing a Coordination Framework and Functional model that advances opportunities in Transmission and Distribution coordination by bringing together cross-sector expertise, shared perspectives, and practical insights.
- Representation from
  - POU
  - CCA
  - WEIM
  - EDAM
  - IOUs

Breaking Down the Effort: A Phased Strategy Discussion

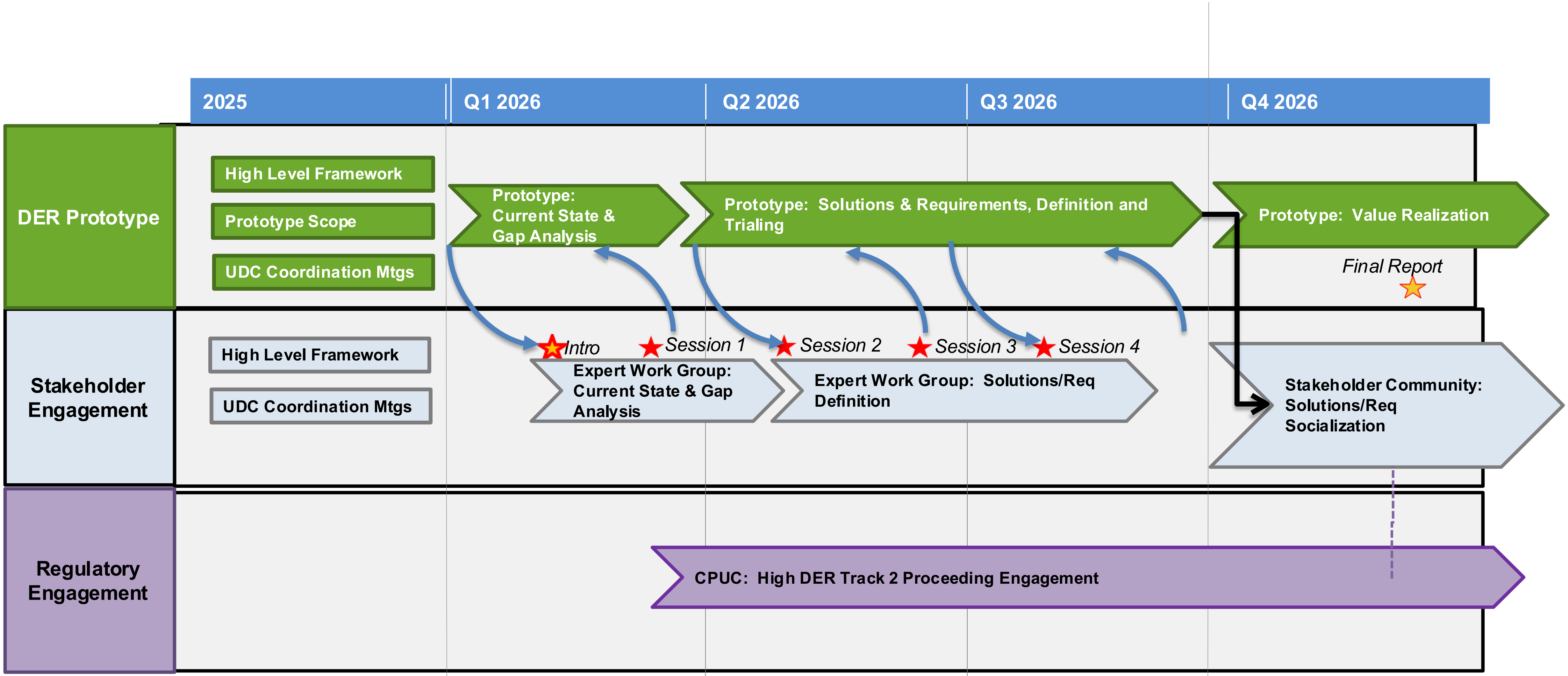
First Phase – Understand the Current State and Gaps

Understand current state of operational coordination & forecasting, and information/visibility gaps

Second Phase – Fill in the Gaps

Leverage learnings to develop and validate coordination solutions, ultimately informing a holistic set of requirements for the mature Coordination Framework to be shared with industry

Coordination Framework Engagement Plan



APPENDIX

Detailed examples of inconsistent modeling and data collection practices

	Example Issues	Process Details
Market Participating resources	Utility distribution and transmission real time monitoring and outage management processes are impacted by flows from market participating energy and demand resources.	• All are subject to ISO and utility agreements, registration, modeling, telemetry, and verification requirements prior to obtaining approval for commercial operations. • The ISO models all, but generally distribution system details are limited (ie resources are mapped to the closest BES substation bank). • Practices for capturing resource and load details for modeling are different for each utility transmission and distribution entity.
Out-of-market resources	ISO operational forecasting, real time monitoring and assessment tools and processes are impacted by OOM energy and demand resources (e.g., Rule 21 Non Export, NEM, utility DR)	• Generally subject to utility agreements, registration, modeling, telemetry, and verification requirements prior to obtaining permission to operate. • Generally modeled only for the utility system to which they connect (distribution or transmission) and are typically not modeled for ISO operations • ISO processes lack modeling and details for anticipating and measuring operating patterns • ISO potentially needs a process for converting rule 21 resources to participate in the market. If export to the grid and market participation is allowed, then additional agreements, telemetry, metering, protection and approvals may be needed.
Other resources	Utility distribution and transmission systems and ISO processes are impacted by flows from unknown energy, demand and load-modifying resources managed by non-IOU entities.	• Generally subject to utility and 3rd party agreements, registration, modeling, telemetry, and verification requirements prior to obtaining permission to operate. • Not generally modeled by the ISO • Utility modeling may be limited to retail interconnection requirements and operating limits • ISO and utility processes lack details for anticipating and measuring operating patterns
Load	ISO does not have a consistent process for modeling load and maintaining over time.	• Includes all utility retail customers as well as large commercial, industrial, EV charging, and data center loads, and all are subject to utility retail agreements and verification requirements. • Utility distribution operations model load to feeders • ISO and utility transmission operations model load at BES substation banks, but lack criteria for “BES impacting” load and additional modeling requirements which may be needed to anticipate and measure operating patterns

DSOs: DER Data Sharing Capabilities

Pacific Gas & Electric – Katie Gallinger

San Diego Gas & Electric – Kirsten Peterson, Garrett Wysocki, and Alex Kilmer

Southern California Edison – John Battenschlag and Julian Ang

ISO – DSO Enhanced DER Visibility

High DER Proceeding, Track 2 Workshop
June 5th, 2026

PG&E has lots of Customer DER-related Data*

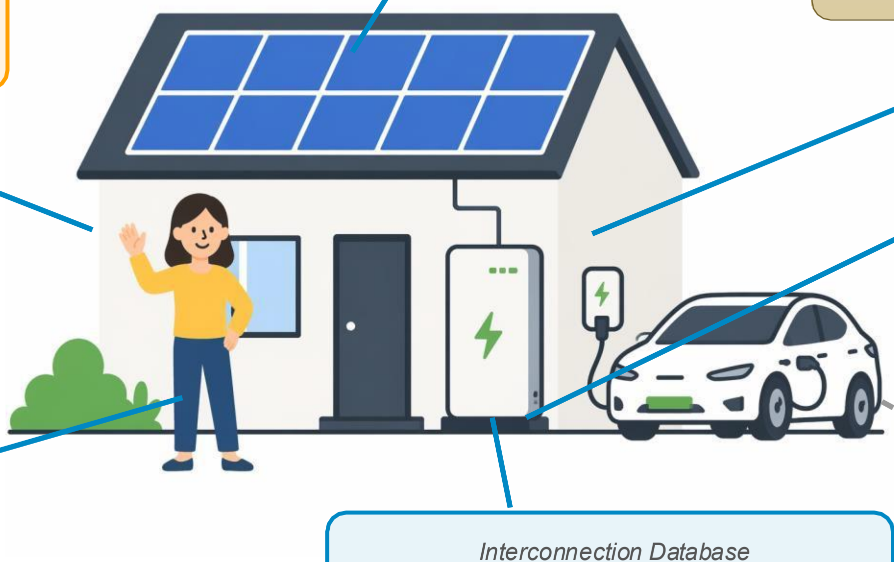
Key data points live in separate, disconnected systems

Interconnection Database
Solar PV System
Size: 7kW

AMI Data
Energy Usage

Billing System
Rate: E-ELEC

SAP
Grid Location



EV?
Not in Managed Charging program
Not on EV rate

DR Management System
DSGS Program
Enrolled

Interconnection Database
Battery Storage
Size: 13kWh
Operating mode: No grid charging

*and much of it is sensitive personally Identifiable Information (PII)

Need to Weigh Value Against Privacy, Complexity, and Cost

GRID

DERMS / ADMS / EMS Real-time grid ops, as-operated model, Dx constraints	**GIS** Grid location, maps, service territory	**Historical Load Trending** Historic grid asset loading data

CUSTOMERS

Interconnection DER specs, system size, operating mode	**AMI / MDMS** Load/meter data, energy usage, DER trends	**Clean Energy Transportation** EV asset data

PROGRAMS & RATES

Billing / Rates Customer rates, usage, hourly flex pricing, EV rates	**Demand Response Platform** Program data, enrollment, DR assets, eligibility, CAISO registration	**DERMS (Flex Connect)** DER dispatch, operating envelopes, enrollment

EXTERNAL / MARKET / PUBLIC

CAISO Market awards, outages, forecasting	**Other Third Parties: OEMs /CCAs / CEC** Aggregator data, external program info, program enrollment	**Publicly Available Data** GRIP tool (ICA and GNA), DG Stats (Installed DERs)

Prioritize data sharing that upholds privacy requirements where realizable value outweighs integration complexity and costs

Key Question: What data has value (and to whom)?

The hypothesis is that more data sharing could drive down costs for customers. Identifying which data, to whom, and at what cadence, is next.

- Data that prevents last minute, high-cost energy or grid services, through improved CAISO forecasting
- Data that allows increased limits for flexible service connection customers, through improved distribution constraint forecasting
- Data that allows existing resources more market participation, reduces the need for additional resource build
- Data that allows for the same DER to provide Dx, Tx, <u>and</u> market services
- Improved situational awareness to ensure, safe, reliable, and economic grid operations

Data Centric Workstreams

	CRAWL	WALK	RUN
Data	• Hypothesize on DER data sources of potential value for defined use cases • Pilot data sharing to determine the value provided by data type • Identify data quality concerns	• Build manual / automated data pipelines for high value data • Standardize data formats and models • Evaluate value of data vs costs of data sharing platform options	• Data shared with required quality, frequency, and scale • Automated data pipelines • Value of data outweighs costs and risks of data sharing systems
Privacy	• Assess customer data privacy requirements • Map sensitive data fields across systems • Obtain required approvals for data sharing as needed	• Implement anonymization and aggregation rules as needed • Propose updates to anonymization rules if necessary	• Privacy-preserving analytics at scale
Secure Data Sharing	• Define minimum viable data sharing processes for TSO-DSO exchange • Establish secure transfer protocols	• Expand scope of shared data elements • Evaluate if existing data sharing tools should be expanded or new tools created	• Fully automated bidirectional sharing at the required frequency

T&D Prototype: Crawl Stage Data

PG&E and CAISO jointly launched the T&D Interface Prototype in late 2025 to improve DER visibility, operational forecasting, and T&D coordination across selected regions.

POTENTIAL DATA OF INTEREST BASED ON PRIORITY USE CASES

PG&E → CAISO   Data shared with CAISO

Customer & Rate Information
- Customer rate (e.g., NEM/NBT, TOU, EV rates, flex pricing)
- Customer type (e.g., Residential, Commercial, Industrial, Ag)
- Customer identifier

Installed DER Information
- DER type, capacity rating, and operating mode
- Substation ID, bank, and feeder mapping
- Known EV and EV fleet customers

Program & Operational Data
- Program participation and enrollment (e.g., DR, Flex Connect)
- DER capacity per program
- Operating limits for WDATs and large flexible loads
- Any non-market programs scheduling operating limitations
- Distribution outage schedules and system conditions

CAISO → PG&E   Data received from CAISO

Market & Dispatch Data
- WDAT dispatch schedules based on Cleared MWs
- Market award data for DER resources
- Transmission system condition and limitation information

Forecasting & Planning
- CAISO demand and DER forecast data (for comparison)
- Forecasting error improvement at selected substations (value driver)

LIMITED GEOGRAPHY   <5 Substations

Geography Drivers
- DER Penetration
- Storage Capacity
- Market-Participating Resources
- Estimated EV Penetration
- DERMS Customer Participation

T&D Prototype: Crawl Stage
Privacy

Large loads and limited program participation provide data privacy challenges

Key Open Questions for Prototype Privacy Framework

Aggregation Sufficiency

Will anonymized MW totals at the substation level meet CAISO's planning and operational needs?

- **15/15 Rule (C&I/Ag):** Min. 15 customers, no single customer >15% of total consumption
- **100/10 (Residential Threshold):** Min. 10 customers, no single customer >10% of total consumption
- **Aggregation Limitations:** Low enrollment in some DER programs or large customers makes aggregation thresholds hard to meet

Customer Consent Model

What are the customer consent requirements for CAISO requested data that falls outside planned aggregation models?

- **Customer Consent:** Need to define which types of data may require customer consent before sharing, for example:
  - Flex Connect Operating Envelopes
  - DIDF Dispatches
  - Market Award Information

Formal Privacy Framework

Document privacy requirements by data type, usage aggregation, and accessibility by specific parties to help inform future work and other potential 3rd party distribution.

- **Data Minimization:** Only collect and share the minimum information necessary for operational needs
- **CCPA/CPRA:** Service provider contracts with CAISO must include required data protection clauses
- **Secure Transmission:** Encrypted channels required; verify active contracts and 3rd party cybersecurity review before sharing

T&D Prototype: Crawl Stage
Secure Data Sharing

Manual Data Sharing
- Requires some data merging
- Can be done today
- Comply with privacy requirements

Automated Data Sharing
- Automated data pulls, and automated merging
- Sent via SFTP or other secure method

API
- Complexity depends on encryption type, what data gets sent, security requirements

System-to-System Integration
- Complexity depends on NERC CIP requirements, physical servers, cybersecurity audits, dedicated operation support

$= Thousands

$=Million(s)

Increasing in cost & complexity

Thank You

Katie Gallinger
Katie.Gallinger@pge.com

SCE's Proposals for TSO-DSO Coordination

High DER Proceeding (R. 21-06-017)
Track 2: Workshop #2
June 5, 2026

SOUTHERN CALIFORNIA EDISON®

Executive Summary

- **The proliferation of distributed energy resources (DER) and flexible loads further emphasizes the need for effective data sharing and coordination that supports the CAISO's core role of balancing generation and demand**
- **The CAISO Coordination Framework Industry Expert Work Group is an appropriate technical forum to define and prioritize use cases that enable effective coordination**
- **SCE is advancing foundational data-sharing capabilities to support a broad set of current and future use cases**
- **Further alignment with CAISO is needed on priority data needs, coordination protocols, and near-term pilots to close critical gaps, with emphasis on improving visibility, forecasting, and operational alignment across the transmission–distribution interface.**

BENEFITS OF GREATER COORDINATION

SOUTHERN CALIFORNIA EDISON®

Opportunity: Advancing DSO-ISO Coordination to Realize Benefits

- As grid evolves with increasing DER penetration and load variability, improving situational awareness and coordination across the transmission–distribution interface is a shared priority.
- SCE strongly supports core objective of improving data visibility and operational coordination between CAISO and the distribution system to achieve multiple key goals:
  - Enhanced forecasting to support reliability
  - Enable more effective use of demand-side flexibility
  - Create customer value and support affordability
  - Enables coordination at the T/D interface
  - Increases predictability and system efficiency

Further Definition of Specific Use Cases is Necessary

- To achieve goals effectively, SCE believes next step should be disciplined, use-case-driven evaluation of specific data sharing proposals that includes:
  - Clearly identifying specific data elements
  - Defining aggregation levels
  - Defining timing and cadence requirements
  - Establishing operational use cases and expected benefits
- This level of specificity is necessary for utilities to:
  - Assess whether existing systems and processes can support the requested data
  - Identify incremental investments or modifications
  - Evaluate cost-effectiveness and potential alternatives

A Use-Case Driven Approach Should Guide Decisions on Future Policy Action

- Once beneficial data sharing or coordination capabilities are identified, utilities will need to evaluate appropriate implementation pathways, including potential investments in systems, integration, and governance.
  - Utilities would seek to recover reasonable and necessary costs through standard ratemaking processes (e.g., GRCs)
  - Proposals would be subject to CPUC review to ensure cost-effectiveness and customer value
- At this stage, however:
  - The scope of potential requirements remains conceptual
  - There is not yet sufficient specificity to define investment needs or policy requirements

Continued Technical Evaluations Should Inform Future Policy Action

- **CAISO Coordination Framework Industry Expert Working Group currently developing and addressing data gaps, use cases, and solutions.**
  - **Expected outcomes:**
    - **Continue through the remainder of the year**
    - **Incorporate broad stakeholder input**
    - **Deliver concrete recommendations on data sharing coordination**
- **SCE believes it is appropriate for the CPUC and High DER Stakeholders to:**
  - **Monitor and stay informed on progress**
  - **Provide a forum for knowledge sharing and alignment where useful**
  - **Consider whether further policy action is needed once proposals are more fully developed**

SCE'S PROPOSED DATA COORDINATION

SCE Joint Alignment with CAISO's Needs

- **Example data types SCE plans to share (SCE →CAISO)**
  - **Day Ahead Forecast – A/AA bank bus net load and A/AA bank aggregated DER generation/demand operating envelope forecast**
  - **Market-adjusted Net Load Feedback – Reflect post-market outcomes (e.g., cleared schedules, DER dispatch impacts) back to CAISO to reconciled distribution conditions with CAISO market decisions, resolving aggregated data masking**
  - **Enhanced Distribution Alarm/Event – Enable awareness of distribution-level anomalies that could affect transmission reliability or market assumptions.**
  - **Real-time (RT) Available Demand Flexibility – inform CAISO how much demand flexibility is expected to be available for the DSO and the potential speed of dispatch.**

SCE'S Proposed Data Coordination

- **Example data types that CAISO should share with DSO (CAISO →SCE)**
  - **Market Dispatch Data – Enable SCE to identify and mitigate distribution violations driven by bulk system dispatch decisions (particularly VPP).**
  - **Inverter-Based Resource (IBR) Dynamic Behavior/Responsiveness Operational Data – Enable SCE to mitigate and plan for IBR-driven oscillations (e.g., voltage/VAR instability), recognizing that IBR response speeds may exceed those of existing Volt/VAR control equipment.**

Full Cycle Coordination Model

FORECAST

SCE (DSO)

- Day-ahead net load & DER operating envelope forecasts
- Real-time available demand flexibility, market adjusted net load and alarm/events

SCE → CAISO

DISPATCH

CAISO (ISO)

- Market clearing & scheduling
- DER/VPP dispatch decisions
- RT reconciled distribution conditions

FEEDBACK

CAISO (ISO)

- Market dispatch data & schedules
- IBR dynamic behavior data

CAISO → SCE

RECONCILE

SCE (DSO)

- Post-market net load reconciliation
- Distribution alarm & event monitoring

Remaining Gaps

- **Key gaps that still require resolution between DO/TO and CAISO:**
  - **Standardized CAISO - SCE data exchange (Enhanced RT coordination)**
    - Forum to address a standardized, agreed upon data models and exchange interfaces between CAISO and SCE.
    - Day-ahead vs. RT vs. Sub-hourly (especially on timing and latency agreements)
  - **Visibility ≠ Coordination**
    - SCE can provide visibility to non-market DER (part of a Demand Flexibility Program or DR) but there is no clear shared CAISO non-market DER operational coordination roadmap.
    - SCE performs Day-Ahead N-1 Contingency Studies to ensure operational coordination exist and is planning to enhance with the output from standardized data exchange.
  - **Roles, responsibilities and accountability across CAISO, TO/DO and DER owners.**
    - SCE can resolve system ownerships and build role and responsibilities in the interfaces, but further discussion is needed for the Full Cycle Coordination Model to work.

Remaining gaps are primarily standardization, alignment, and execution gaps rather than capability gaps needed for full CAISO coordination.

CONCLUSION

SOUTHERN CALIFORNIA EDISON®

Conclusion

- **SCE supports improving coordination and visibility to support reliability and efficient use of demand-side flexibility.**
- **Specific data requirements and operational processes are still under development, and it is critical to define them clearly before evaluating feasibility, cost, and appropriate policy action.**
- **The ongoing CAISO Coordination Framework Industry Expert Work Group is the appropriate venue to develop these details, which will inform whether any targeted policy action is needed.**

High DER Future – R.21-06-017
Workshop #2 DER Visibility and TSO-DSO Coordination

June 5, 2026

Agenda

- Introduction
  - SDG&E Perspective and Guiding Principles
- Current State: DER Landscape, Visibility, and Data Sharing
  - SDG&E's current DER landscape
  - Current data sharing capabilities
- Future Plans: Improved DER Visibility, Telemetry, & Operability
  - Visibility, Management, and Control Roadmap
  - Data Visibility Layer Discussion
  - Future Data Capabilities
- Data Synergy
  - Opportunities for Collaboration
- Conclusion

Introduction

SDG&E's Perspective & Guiding Principles

SDG&E Perspective and Guiding Principles

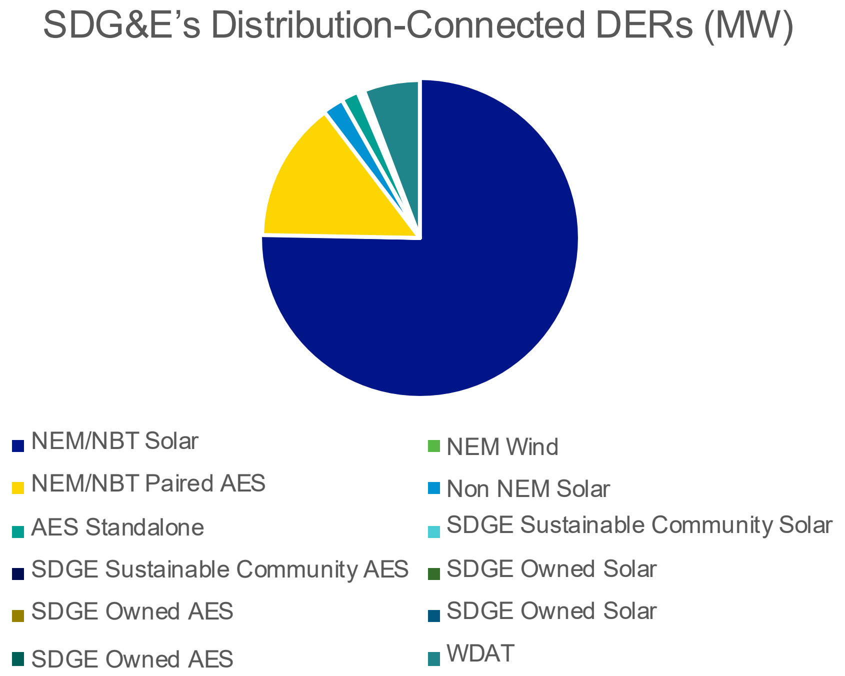
- Strive for customer-focused, reliability-driven data sharing
- Clearly define problems being addressed, data requirements, and incrementally build on the existing data-sharing foundations
- Pursue visibility of DERs where necessary, while ensuring compliance to privacy rules and grid cyber safety
- Ensure clear ratepayer value before scaling investments – infrastructure and IT costs to increase DER visibility and data-sharing capabilities must demonstrate tangible benefits to customers; where value streams are still being developed, a measured, incremental approach is prudent
- Leverage pilots and targeted initiatives to validate benefits and inform the scope of larger investments before committing to broad-scale deployment

Current State

DER Landscape, Visibility, and Data Sharing

SDG&E's Current DER landscape

- High penetration of BTM DERs (solar, storage, EVs)
- Limited visibility with current technology, impact on forecasting and operations
- Data sharing with CAISO via ICCP
- Telemetry requirements:
  - WDAT projects
  - Rule 21 projects >1 MW
- BTM visibility gap:
  - Only required for Rule 21 projects with PCC >1MW
  - AMI 1.0 cannot disaggregate DER from total load
- Need for enhanced visibility:
  - Increased granularity and spatial awareness
  - Improved modeling → more accurate power flow



Total: 3282.8 MW

Current Data Sharing Capabilities

Aggregated DER capacity and program-level data sharing

Limited telemetry and operational data streams for BTM DERs

Interconnection requirements for Rule 21 and WDAT FTM assets require telemetry

Basic data exchanges: capacity and availability

Forecasting with limited representation of non-weather-based DER behavior

Key limitations: granularity, timeliness, system integration

Current DER Data Flow: SDG&E ↔ CAISO

DER Assets

DERs (WDAT / Rule 21) with Telemetry
- Large PV Arrays
- Large BESS Sites
- Transmission-Connected Resources
- Rule 21 Projects > 1 MW

BTM DERs (Limited Visibility)
- NEM/NBT Rooftop Solar
- Paired Storage
- Customer-Owned EVs
- No dedicated telemetry for Rule 21 with PCC < 1 MW

SDG&E Systems

SCADA / ICCP Telemetry
3-second polling • RIG analog/digital data • FTM sites

Gen Ops / E&FP (Affiliate-Separated)
Monitors CAISO setpoints • Separate from DSO/TSO operations

ADMS
As Switched power Flow • Outage Management • Forecasting

AMI / MDMS
Net meter data • AMI 1.0 cannot disaggregate DER from total load

CAISO

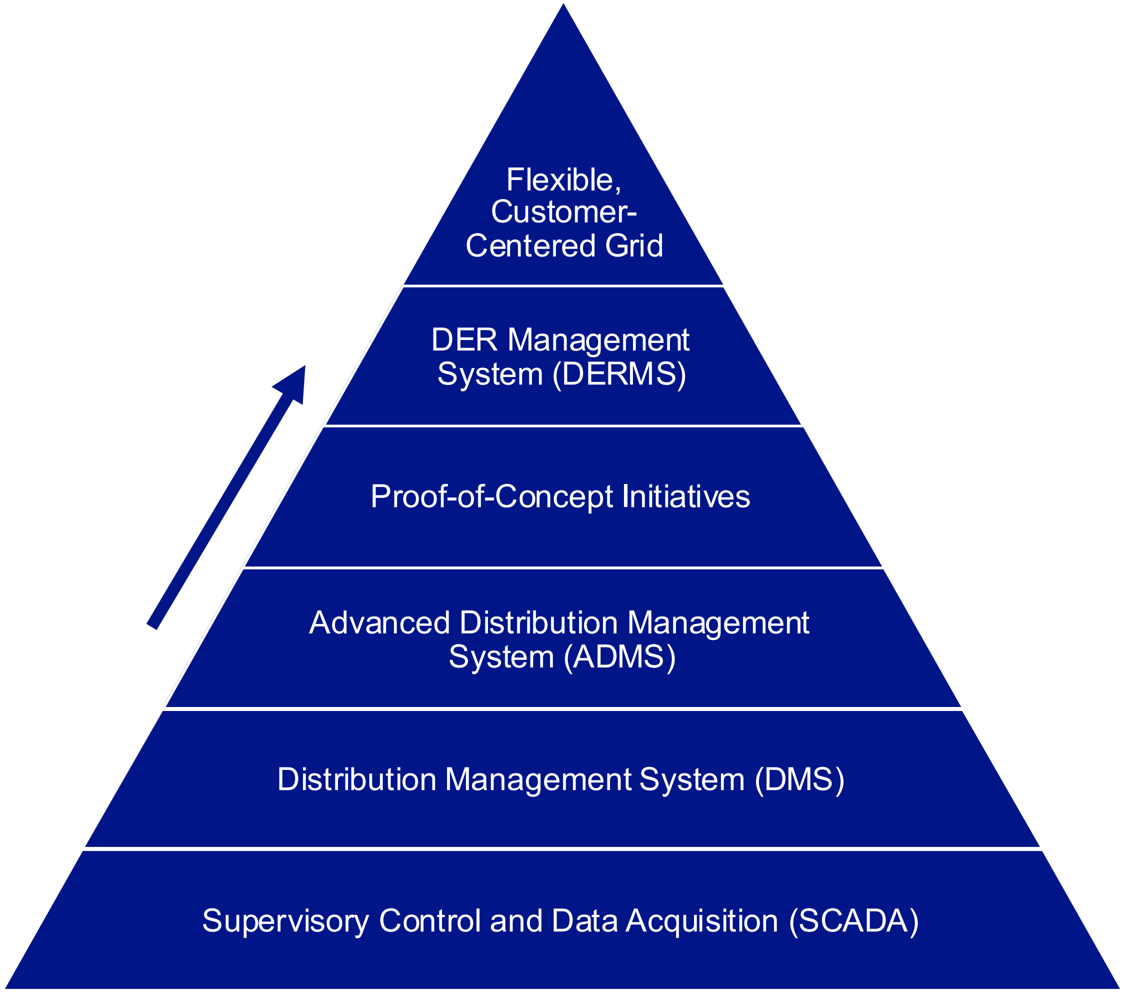
CAISO RIG (Telemetry Ingest)
- Receives 3-second RIG polling data
- MW, MVAr, kV, SOC, ramp rates, upper limit, lower limit
- MV90 data

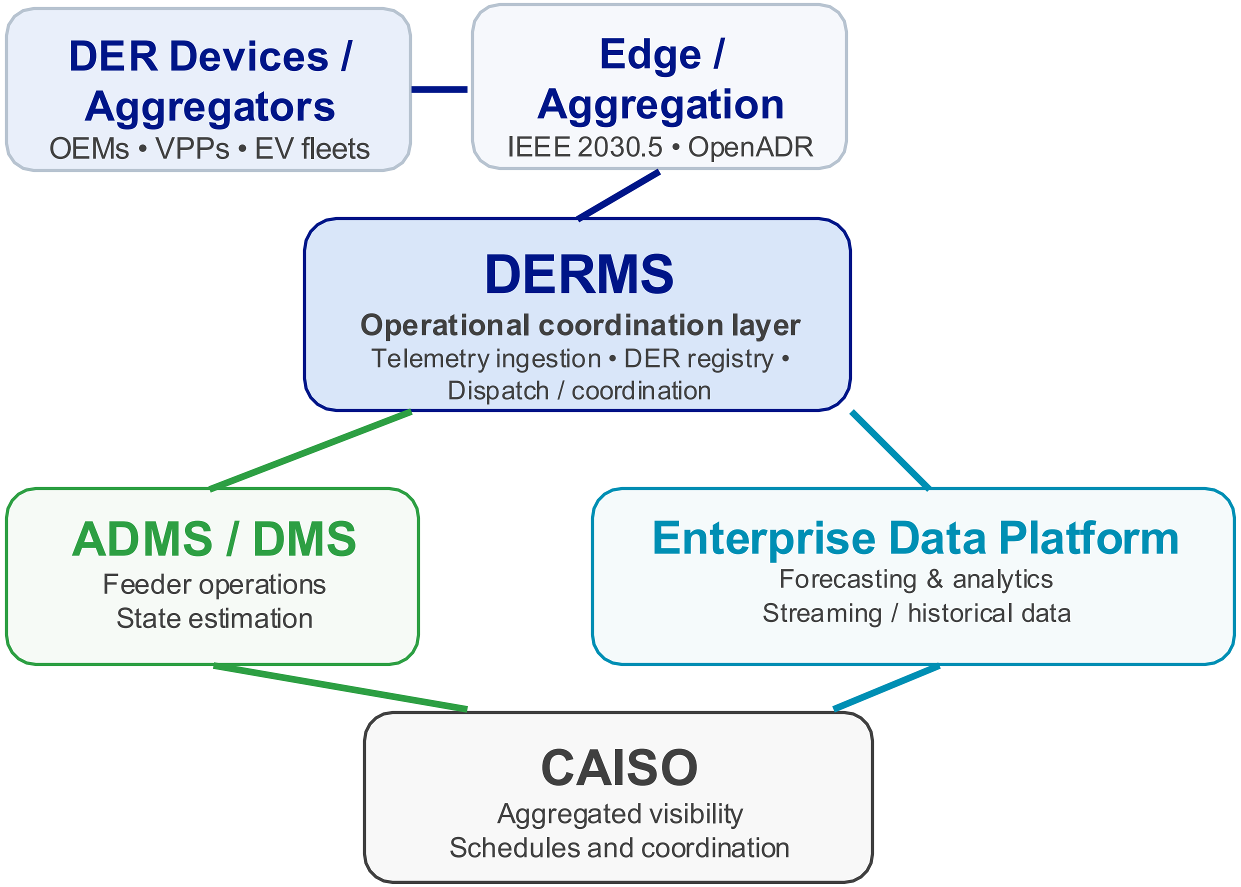
Market Operations (ADS / AGC)
- ADS: 5-min dispatch setpoints to sites
- AGC: 3-second direct setpoint control
- Market awards and WDAT schedules

Future Plans

Improved DER Visibility, Telemetry, &
Operability

Visibility, Management, and Control Roadmap





Data Visibility Layer Discussion

Visibility Layers

Selective Device-Level
Critical DERs and utility-controlled DERs
Real-time telemetry (seconds)
Targeted use for high-value grid services

Aggregated Fleet
Aggregators / VPPs
5–15 min telemetry and market participation data
Primary scalable path for many DER programs

Feeder-Level Operations
SCADA + ADMS state estimation
Voltage, load, topology, and switching awareness
Near-real-time operational core

Customer / AMI Layer
Net load visibility for BTM solar, storage, and EV
AMI data today; higher resolution with AMI 2.0
Supports validation, forecasting, and planning

Higher
granularity
& control

Future Data Capabilities

- SDG&E's Enterprise DERMS procurement in 2027
  - Integration, validation, and customer program enrollment/participation management of Distribution Interconnection Information System (DIIS) DER registry
    - DERMS will sync GIS, DIIS, ADMS data sources to enable a more real-time snapshot of DER contribution and enrollment status at any given time
  - Weather telemetry
  - Enhanced forecasting accuracy and system modeling
    - Non-weather-based DER profiles assigned to model charging/discharging behavior to contribute to a more accurate power flow solution
- AMI 2.0 for higher-resolution data
- Workshop-informed evaluation of potential CAISO data sharing enhancements

Data Synergy

Potential SDG&E & CAISO Data Sharing Protocol Enhancements

Opportunities for Collaboration

01

Align on Operational Challenges

- Collaborate with CAISO and stakeholders to clearly define the specific operational challenges that enhanced DER visibility and TSO-DSO coordination are intended to address
- Establish shared priorities around key issue areas
- A common understanding of the problems is a prerequisite to identifying the right solutions

02

Define Data Needs & Coordination Mechanisms

- Use the identified challenges to inform the scope, granularity, and cadence of data exchange between CAISO and the IOUs (e.g. WDAT and VPP dispatch schedules sent back to IOUs)
- Determine minimum viable data standards that address near-term operational needs while accommodating future capabilities (e.g., DERMS, AMI 2.0)
- Clarify roles and responsibilities across the coordination ecosystem — including LSEs, scheduling coordinators, aggregators, and third-party DER providers

03

Anchor Investments in Customer Value

- Ensure that investments to support enhanced data sharing are guided by the clearly defined challenges and deliver demonstrable benefits to customers and the grid
- Advance incrementally — leveraging targeted pilots and proven use cases to validate benefits before scaling to broader deployment
- Align the pace and scope of investment with the maturity of the coordination framework and the value realized at each stage

Conclusion

Looking Ahead

Conclusion

- SDG&E supports a value-driven approach to enhancing DER visibility and data-sharing capabilities, ensuring that investments are cost-effective and deliver measurable benefits to customers and the grid.
- Effective TSO-DSO coordination requires clear alignment between CAISO and the IOUs on the specific operational challenges to be addressed and a shared understanding of the data needed to address them.
- As the Commission continues to develop the DER orchestration framework, SDG&E encourages a focus on ensuring that data-sharing investments are guided by clearly demonstrated customer benefits — advancing incrementally from targeted pilots and proven use cases toward broader deployment as value is established.
- SDG&E is committed to collaborating with CAISO, the Commission, and stakeholders to advance DER visibility in a manner that is both technically sound and prudent for ratepayers. We look forward to continued dialogue on defining shared priorities, establishing practical coordination mechanisms, and ensuring that the pace and scope of investment reflect the value delivered to customers and the reliability of the grid.

SDGE™

Q&A

Lunch

We’ll be back at 1:30 pm

Centralized Data Exchange and Technology Platform Considerations

Open Access Technology International – Ali Ipakchi

Piclo - James Johnston, Shubha Jaishankar and Dain Nestel

DER Orchestration: DSO-CAISO Operational Coordination and Data Exchanges

Ali Ipakchi

June 5, 2026

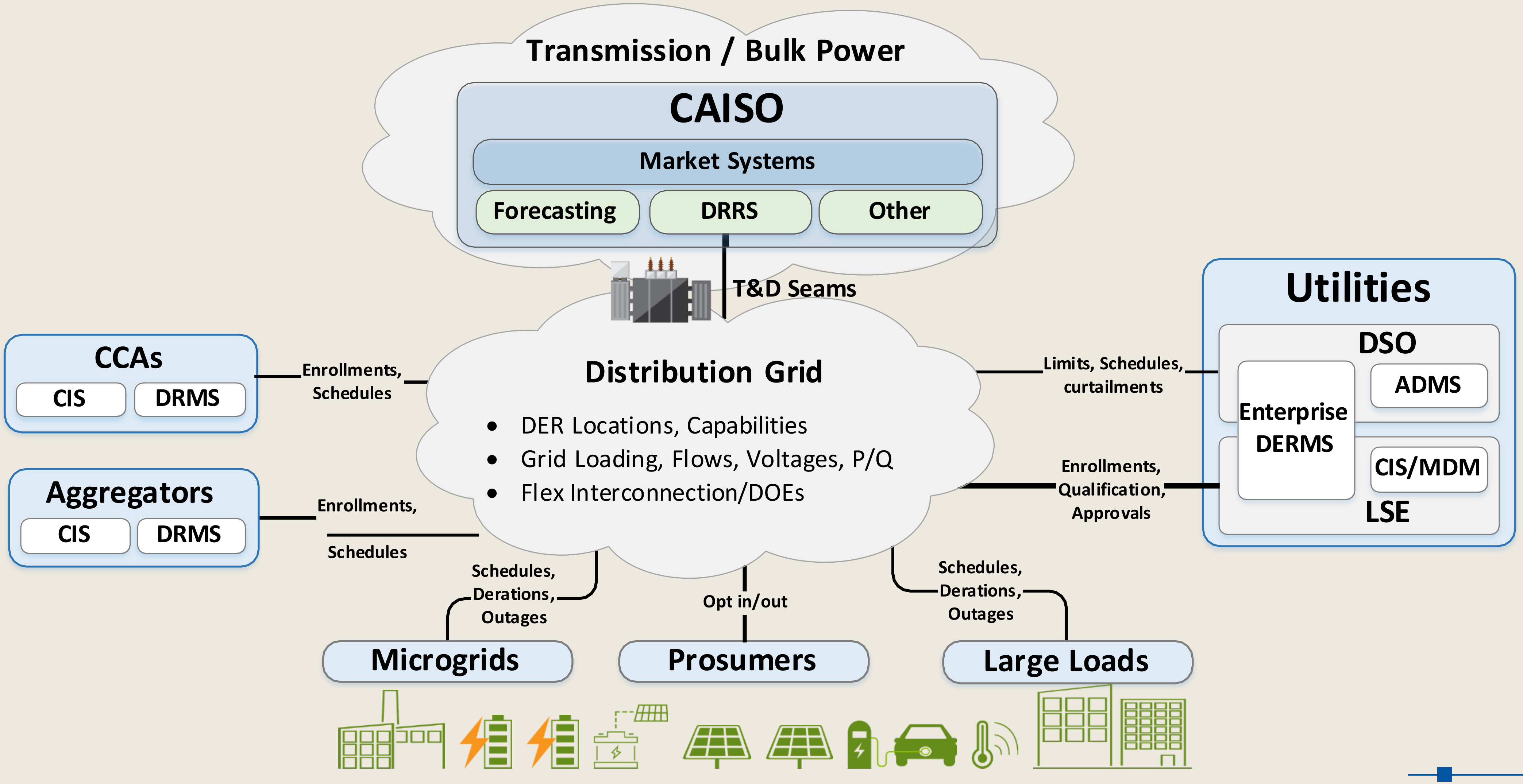
Overview of Illustrative Technology Capabilities for DER Data Exchange and Coordination

This presentation highlights illustrative technology capabilities and architectural approaches that could enable scalable, secure, and interoperable data exchange ecosystems in a high-DER environment, including:

- Coordination across aggregators, distribution operators, and grid operators through data exchange frameworks
- Improved planning, situational awareness, and forecasting enabled by timely, standardized data flows
- Enhanced market efficiency through scalable and flexible integration of DERs and demand-side resources

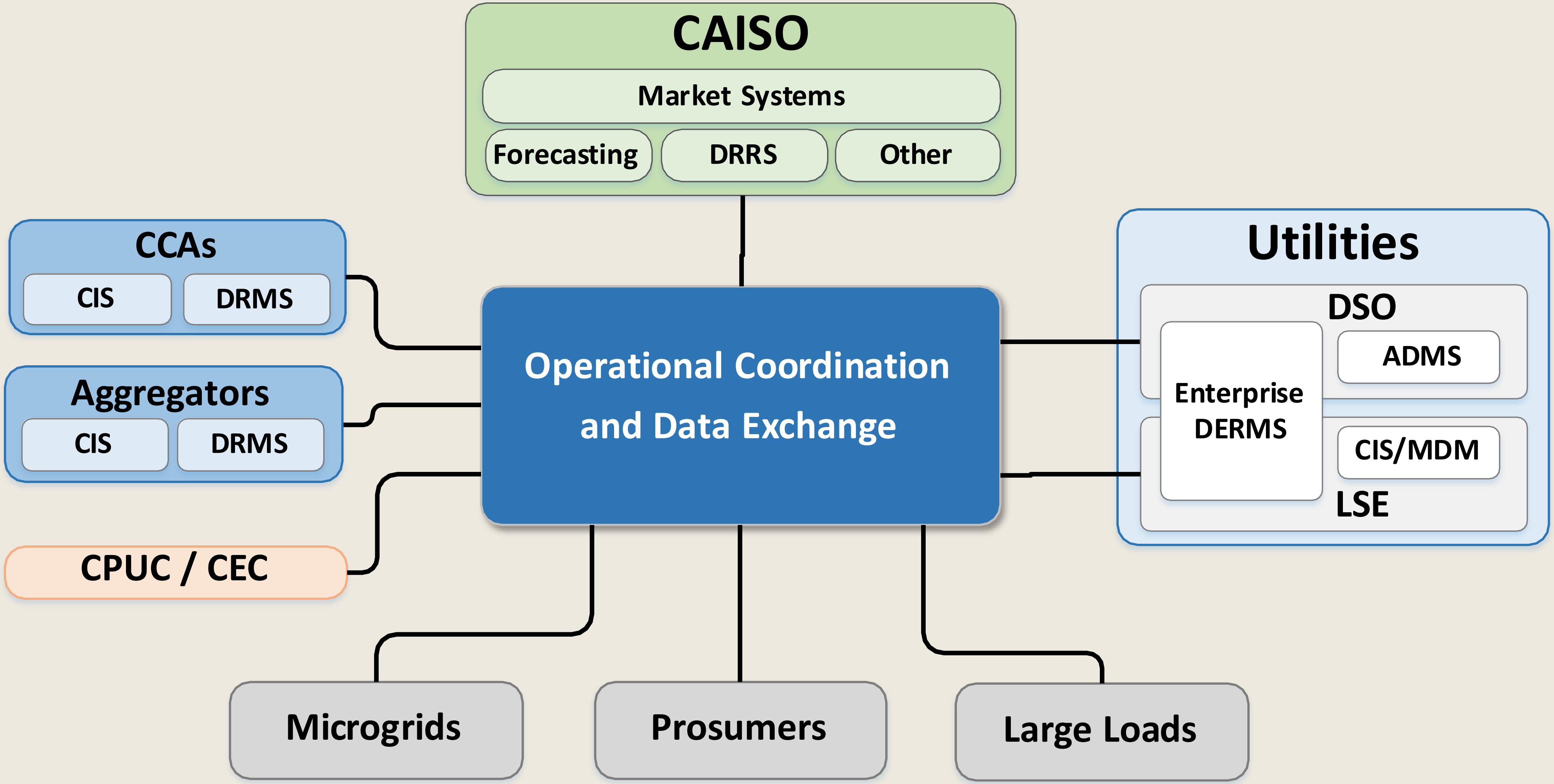
High DER Operation

Need for operational coordination across the stakeholders



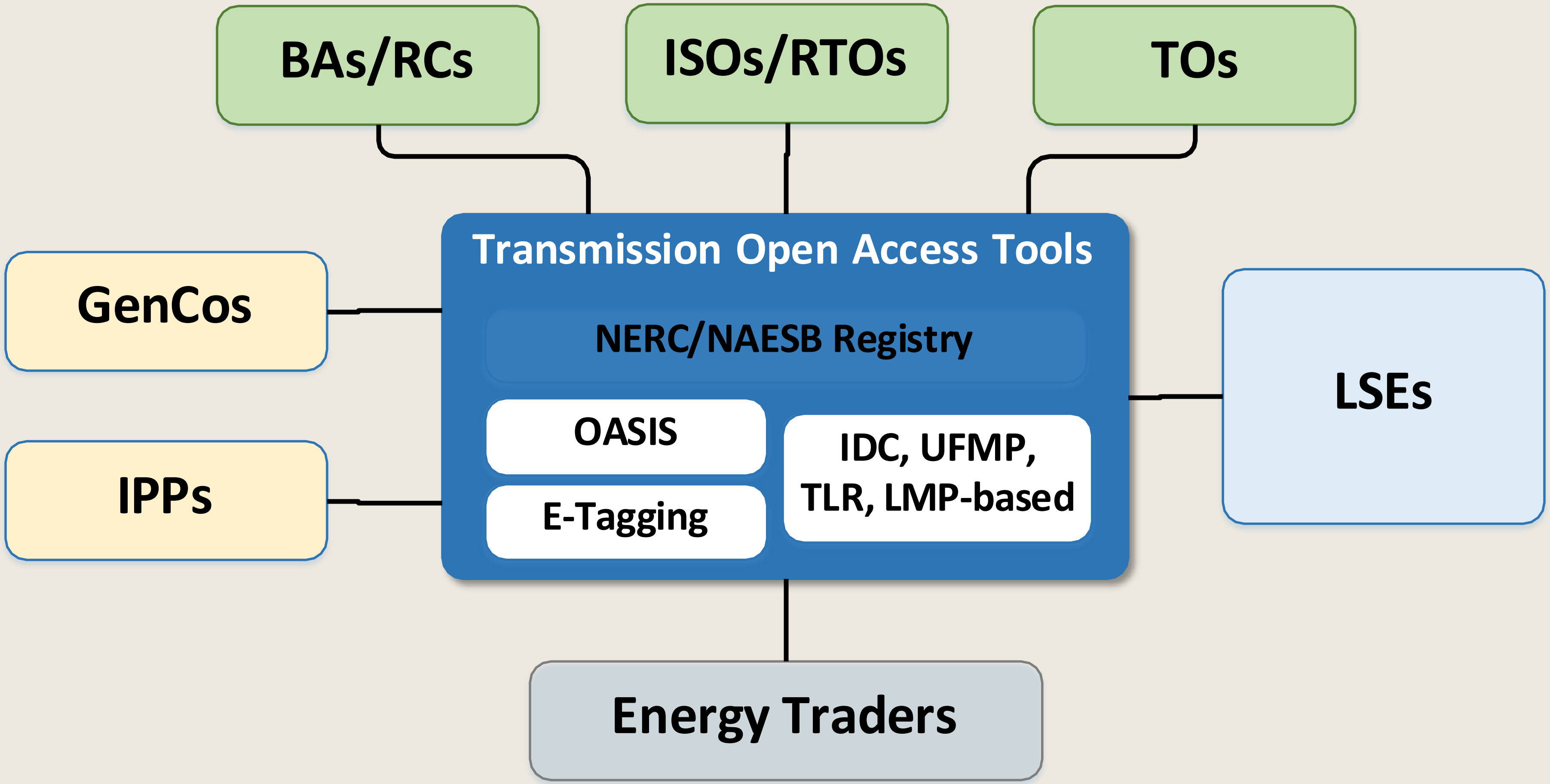
System Overview

Operational Coordination and Data Exchange – A Unified Platform



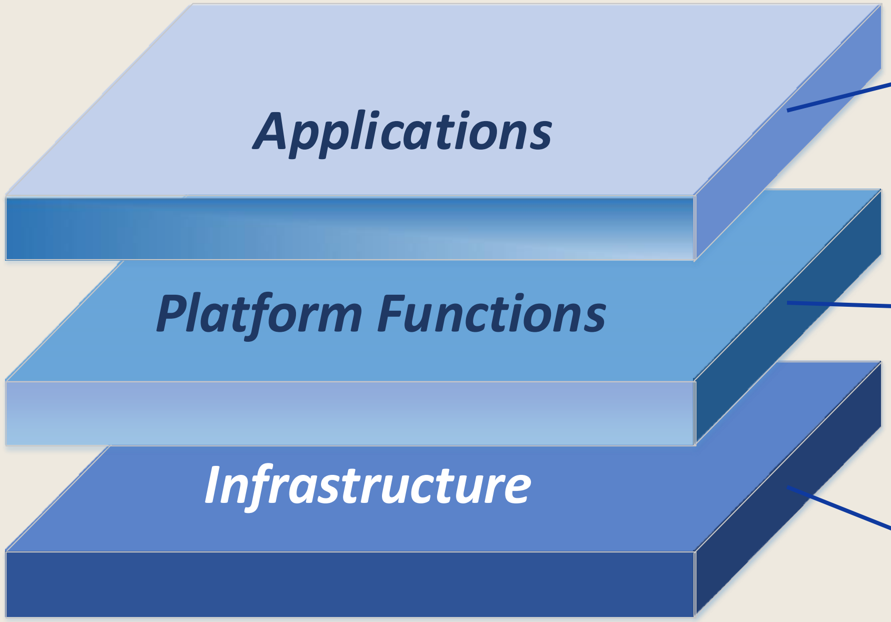
FERC 888/889: Transmission Open Access

Similar software tools and procedures that has enabled Transmission Open Access operation (Circa late 1990s)



Reference Architecture - Ops Coordination

Application use cases have been identified, base technologies are available, layered system design is recommended



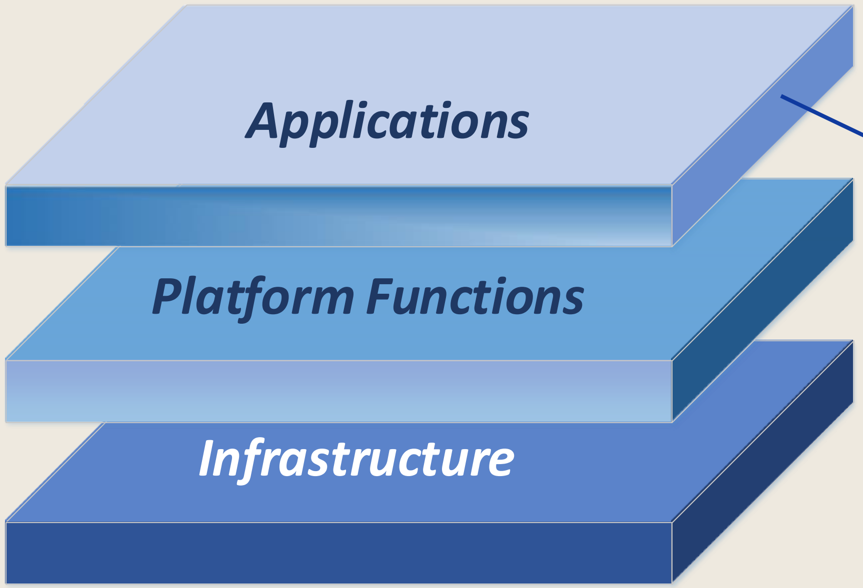
- Use Cases
- Portals and APIs – Open Standards
- Operational Workflows

- User Management
- Workflow Management
- Business Rules
- Transactional Management

- Scalability
- Performance
- Cyber Security
- Information Privacy

Platform Use Cases

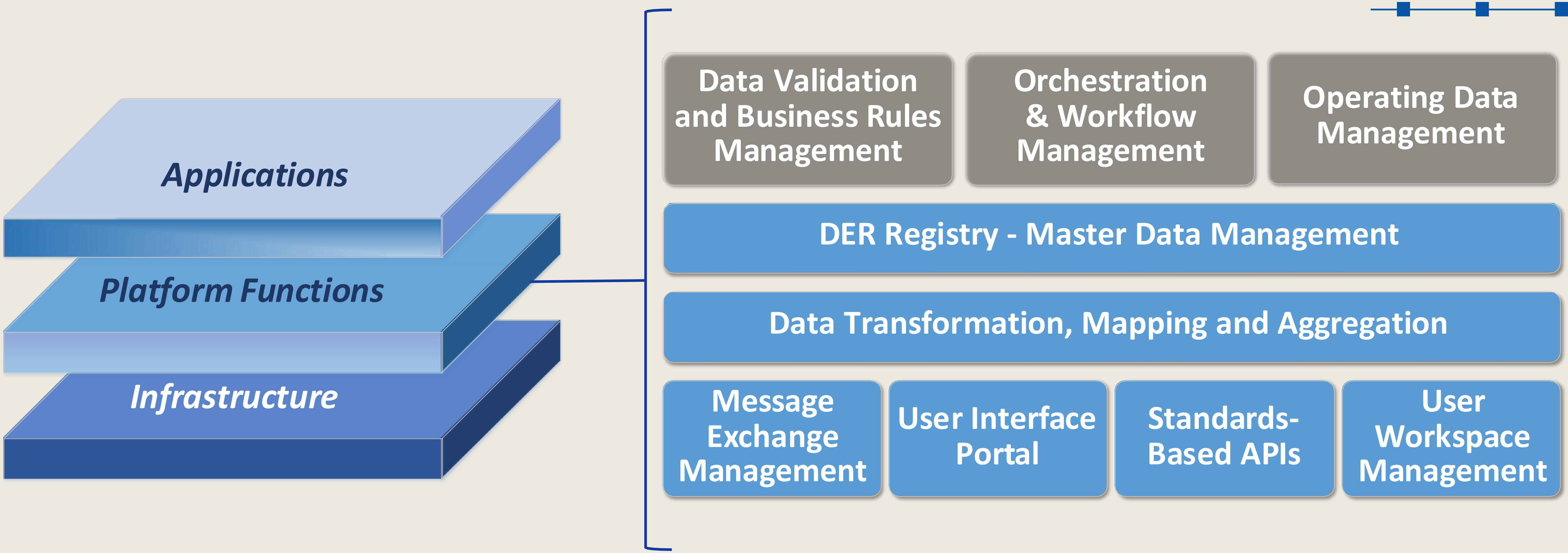
The system enables operational coordination between service providers, utilities and CAISO



- Entity and Resource Registration
- Operational Coordination
- Improved Operational Forecasting
- Look Ahead Situational Awareness
- Improved System Planning

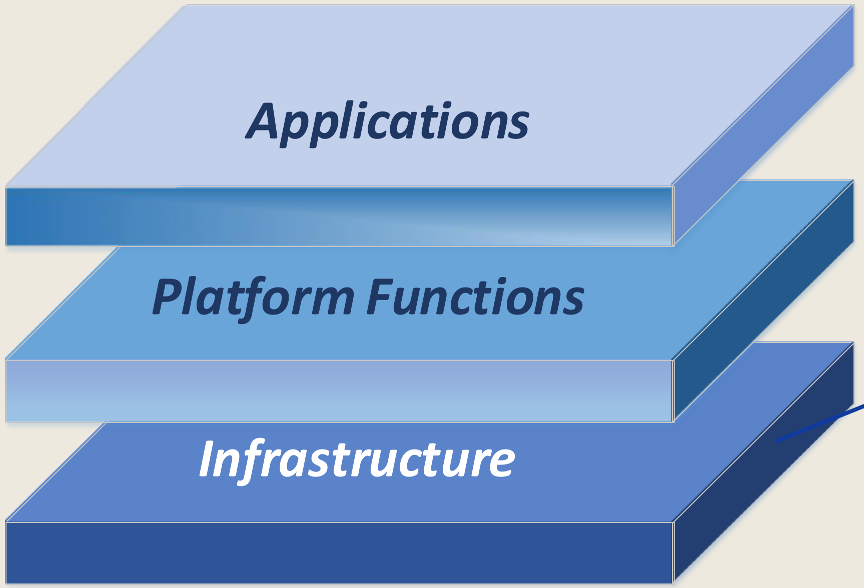
Platform Functions and Capabilities

Base capabilities will enable configuring of target use cases and operational capabilities



Cloud-based Architecture

A secure cloud-based hardware infrastructure and data communications platform

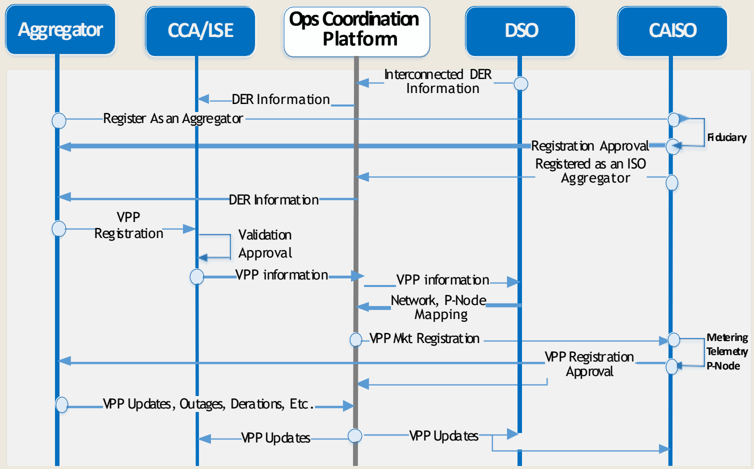


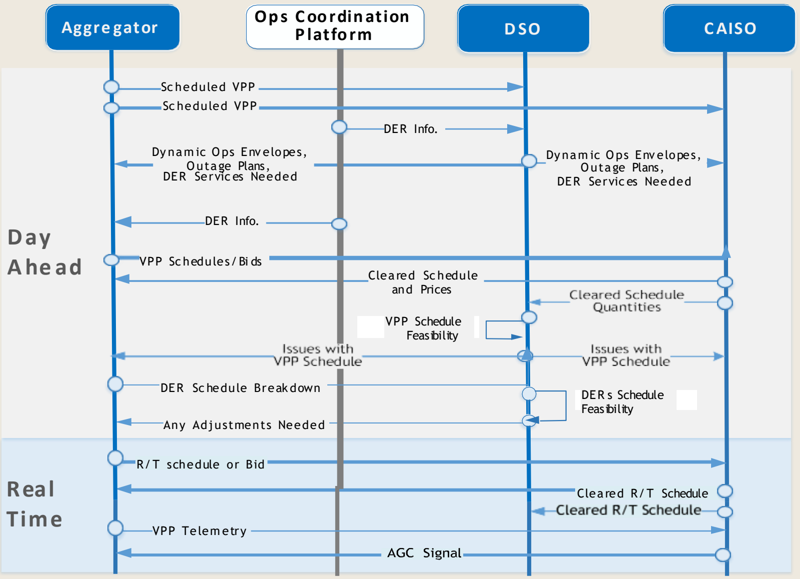
- Scalable Cloud-Bases Solution
- Security, Trust and User Access Control
- Scalability and Performance Management
- Data Management and Storage
- Transactions and Process Management

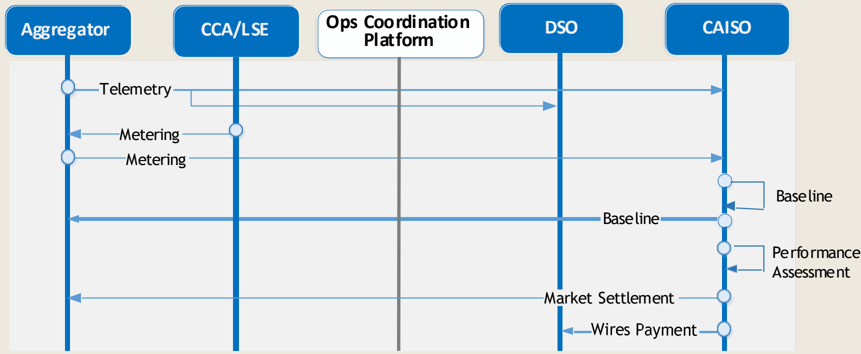
Workflows

Establishing the required workflows, roles and responsibilities, and timing is essential to DER orchestration

Pre Operation | **Operation** | **Post Operation**







Key Considerations

- **Enabling technologies available** – scalable, secure platforms; mature data models; interoperability standards; portals; and data-exchange mechanisms
- **Scope of required functionality** – use cases must be identified and prioritized
  - **DER Registry definition** – participating and non-participating DERs
  - **Grid services coverage –**
    - CAISO market products (Transmission / Bulk Power)
    - Distribution operations (Economics vs. Reliability)
  - **Situational awareness and forecasting** –
    - Outages and derations
    - Granular net-load forecasts
  - **Topology and mapping** – Seams, sub-LAPs, pricing nodes
- **Business process framework** – roles, responsibilities, data-exchange sequences, and business rules
- **Tariff and regulatory considerations**
- **Deployment and rollout strategy** – phased implementation approach

Call to Action

Phased Deployment Approach

Phase I:

- Core Capabilities
  - DER Registry 1.0
  - DSO-CAISO Operational Coordination (Market Participation)
  - Net-load forecast at T&D seams
- Requirements Specification (6-9 months)
  - Publish straw requirements
  - Conduct stakeholder workshops – review, refine, and approval
- System Development (12 months)
  - A cloud-based SaaS implementation
  - Systems Integration, training, and support
  - Testing and verification (3 months)
  - Statewide rollout

Thank You !

Any Questions ?

piclo®

Independent flexibility marketplace

TSO/DSO Coordination Workshop

CPUC June 5, 2026

Agenda

- About Piclo
- Using a marketplace to drive visibility of DER assets
- Flexibility Marketplace Architecture
- TSO-DSO coordination Case Study
- Final remarks

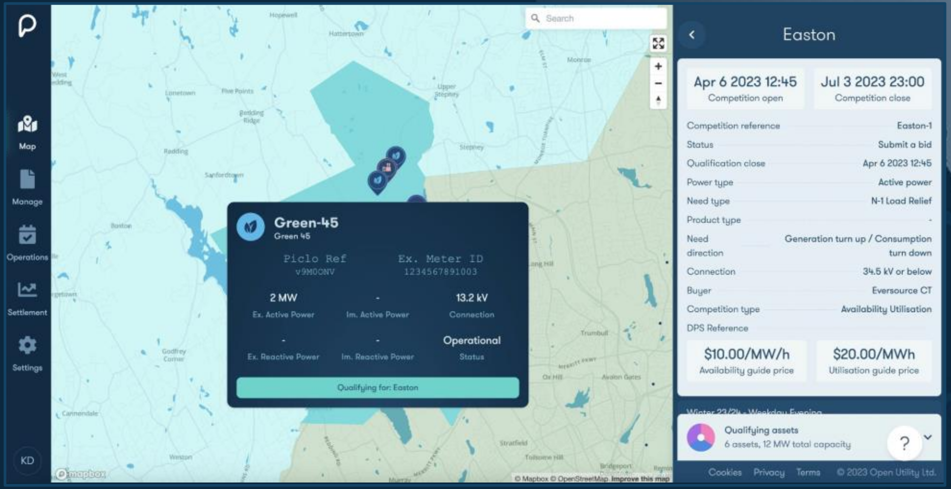
Piclo Marketplace

Unlocking load growth through **flexibility markets**

$100m
Of flexibility contracts awarded

40 GW+
DER across **500k+ sites**

500+
members in **6 countries**



Timeline

2018 → UK launch with all six distribution utilities
2023 → US launch with National Grid in NY
2025 → NA-wide coverage of all utility DR programs

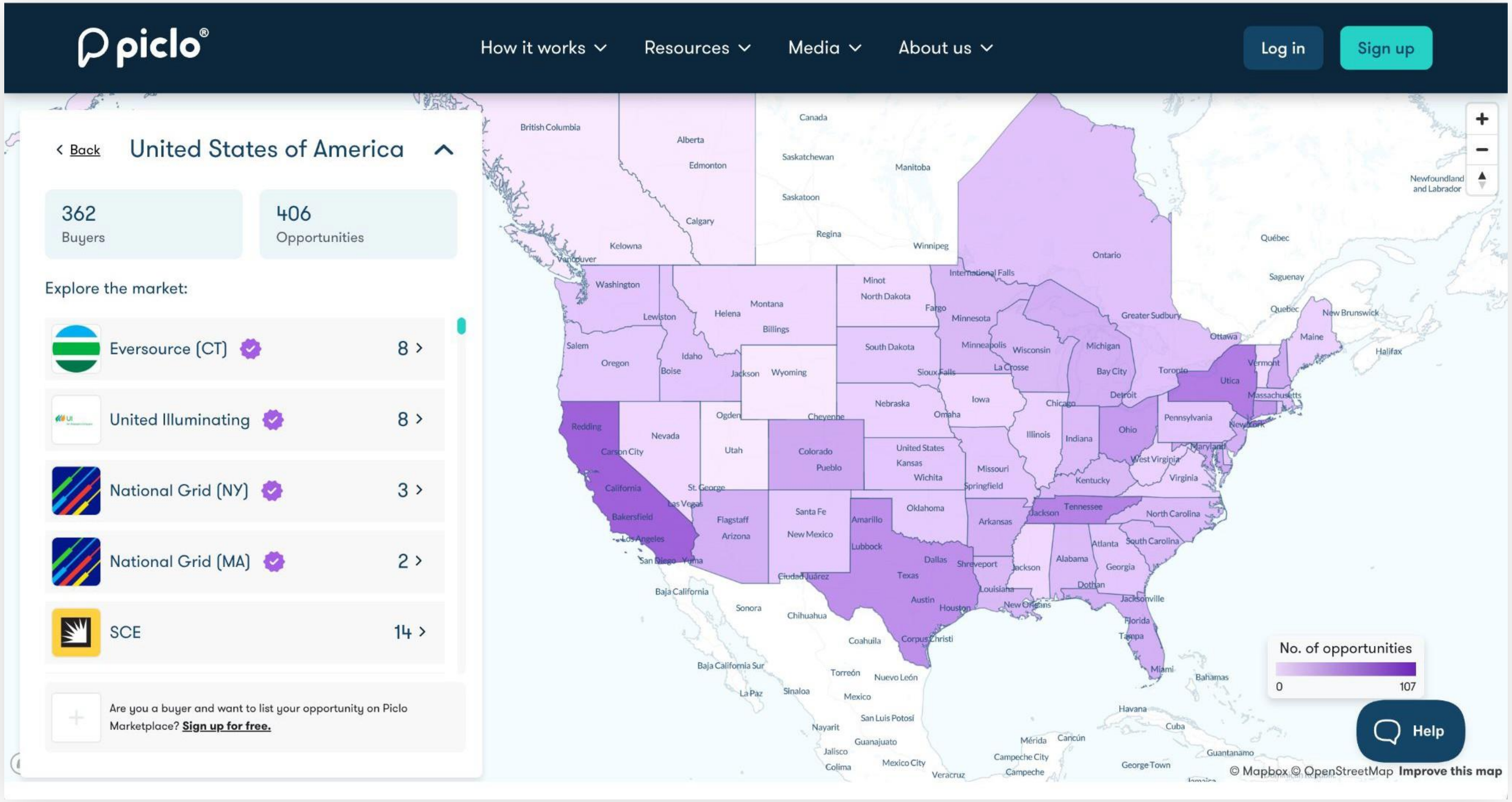
About Us

- Award-winning marketplace innovator since 2013
- Global team of experts
- **$30m+** raised incl. EDP Ventures

nationalgrid | NORTHERN POWERGRID | NESO National Energy System Operator | nationalgrid DistributionSystemOperator | e-distribuzione | E-REDES | Powercor AUSTRALIA | ORES | Northern Ireland Electricity Networks

EXTERNAL

4GW of DER across 50 states within 12 months of launch

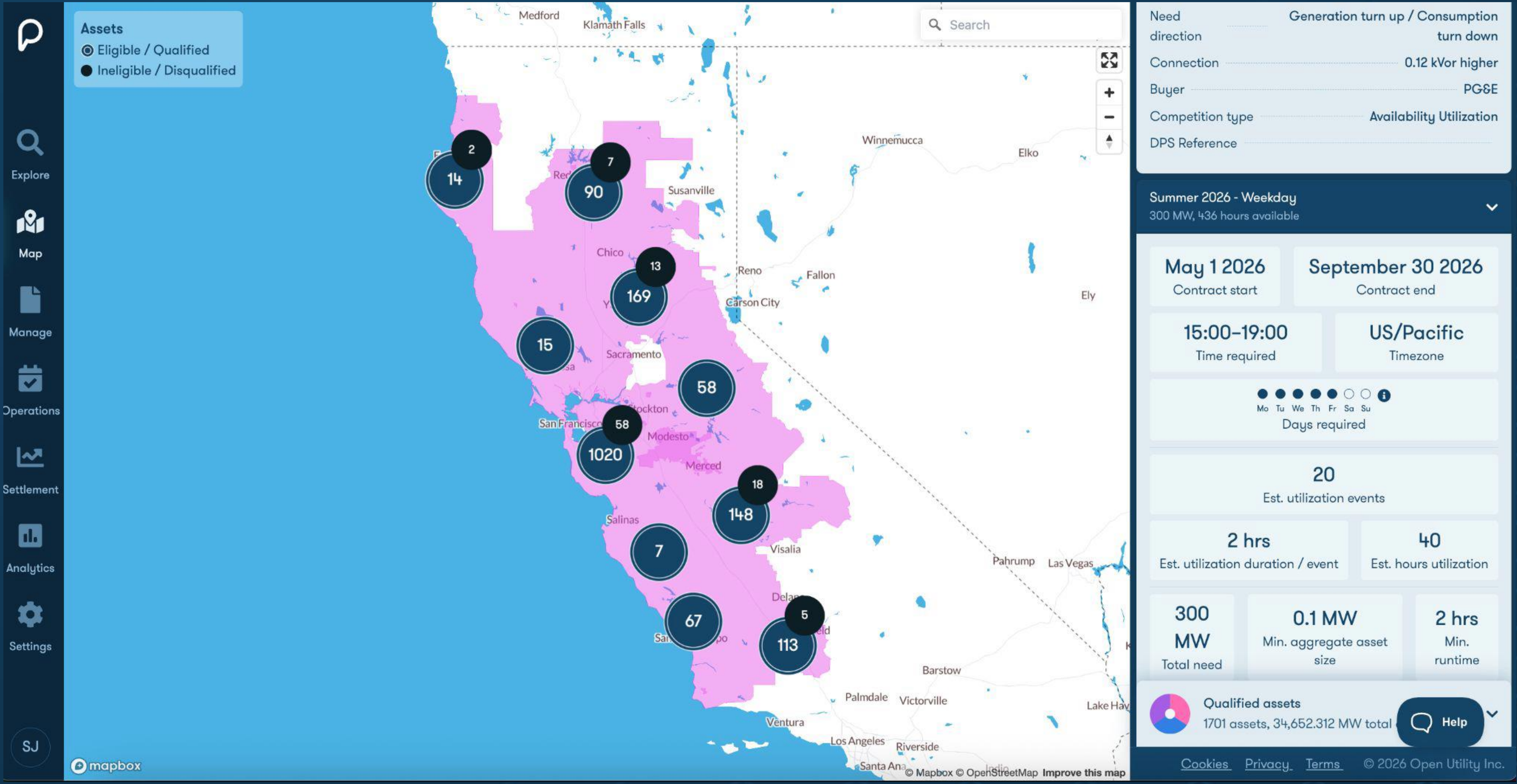


Registered USA Sellers:

BASE
BUDDERFLY
CPower
enel x
leap
Renew Home
sonnen
sunrun
TESLA
voltus

200+ more

Using a marketplace to drive visibility of DER assets


Explore
Map
Manage
Operations
Settlement
Analytics
Settings
SJ
Assets
Eligible / Qualified
Ineligible / Disqualified
Search
Medford
Klamath Falls
Susanville
Winnemucca
Elko
Chico
Reno
Fallon
Carson City
Ely
Sacramento
Stockton
San Francisco
Modesto
Merced
Salinas
Visalia
Pahrump
Las Vegas
Barstow
Palmdale
Victorville
Ventura
Los Angeles
Riverside
Santa Ana
mapbox
© Mapbox © OpenStreetMap Improve this map
Need direction
Generation turn up / Consumption turn down
Connection
0.12 kVor higher
Buyer
PG&E
Competition type
Availability Utilization
DPS Reference
Summer 2026 - Weekday
300 MW, 436 hours available
May 1 2026
Contract start
September 30 2026
Contract end
15:00-19:00
Time required
US/Pacific
Timezone
Mo Tu We Th Fr Sa Su
Days required
20
Est. utilization events
2 hrs
Est. utilization duration / event
40
Est. hours utilization
300 MW
Total need
0.1 MW
Min. aggregate asset size
2 hrs
Min. runtime
Qualified assets
1701 assets, 34,652.312 MW total
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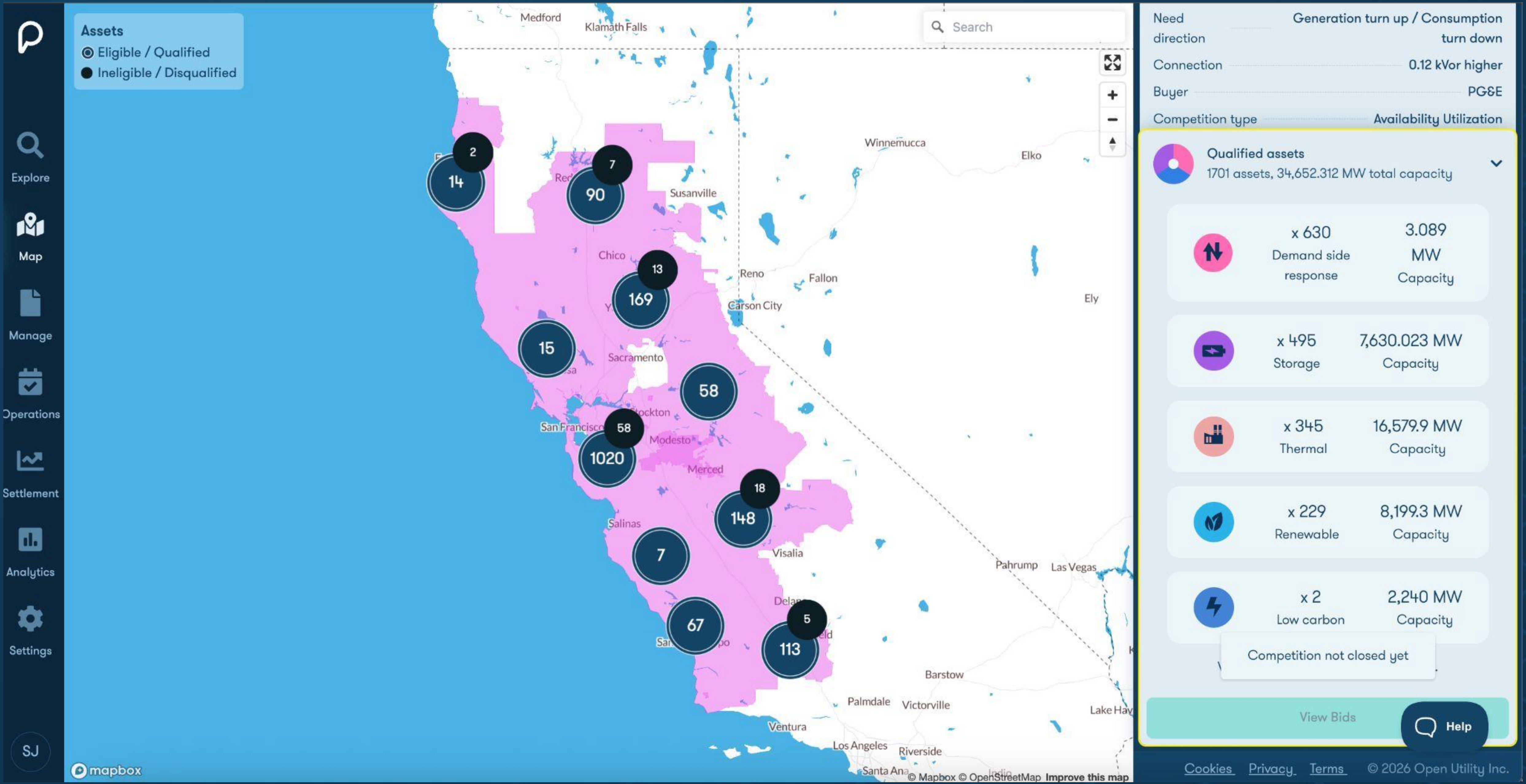
EXTERNAL



Assets
Eligible / Qualified
Ineligible / Disqualified
Explore
Map
Manage
Operations
Settlement
Analytics
Settings
SJ
Search
Medford
Klamath Falls
Susanville
Chico
Winnemucca
Elko
Reno
Fallon
Carson City
Ely
Sacramento
San Francisco
Stockton
Modesto
Merced
Salinas
Visalia
Pahrump
Las Vegas
Barstow
Palmdale
Victorville
Ventura
Los Angeles
Riverside
Santa Ana
Lake Hav
2
14
7
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13
169
15
58
58
1020
18
148
7
67
5
113
mapbox
© Mapbox © OpenStreetMap Improve this map
Need direction
Generation turn up / Consumption turn down
Connection
0.12 kVor higher
Buyer
PG&E
Competition type
Availability Utilization
Qualified assets
1701 assets, 34,652.312 MW total capacity
x 630
Demand side response
3.089 MW Capacity
x 495
Storage
7,630.023 MW Capacity
x 345
Thermal
16,579.9 MW Capacity
x 229
Renewable
8,199.3 MW Capacity
x 2
Low carbon
2,240 MW Capacity
Competition not closed yet
View Bids
Help
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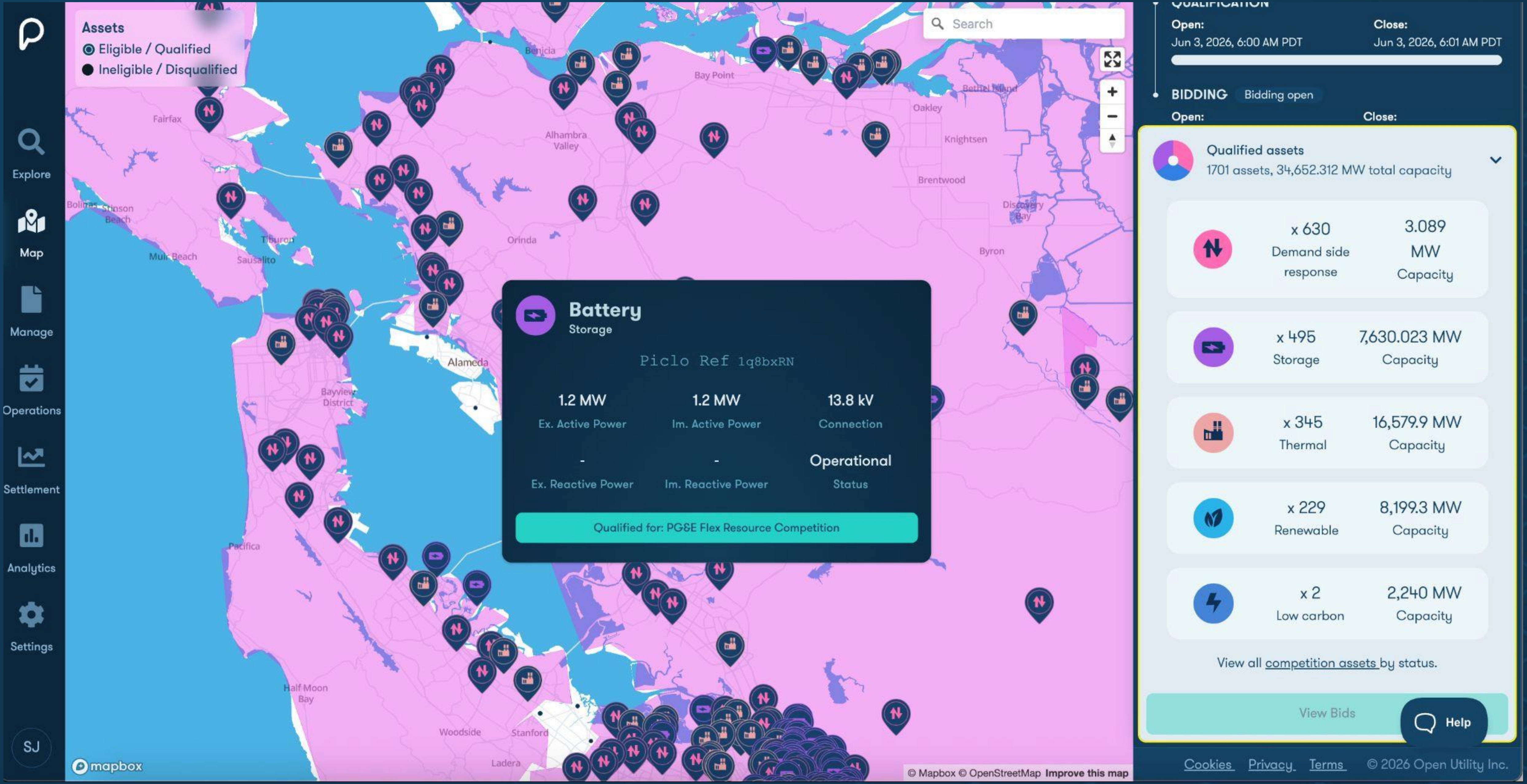
Assets
Eligible / Qualified
Ineligible / Disqualified
Explore
Map
Manage
Operations
Settlement
Analytics
Settings
SJ
Search
QUALIFICATION
Open:
Jun 3, 2026, 6:00 AM PDT
Close:
Jun 3, 2026, 6:01 AM PDT
BIDDING
Bidding open
Open:
Close:
Qualified assets
1701 assets, 34,652.312 MW total capacity
x 630
Demand side response
3.089 MW
Capacity
x 495
Storage
7,630.023 MW
Capacity
x 345
Thermal
16,579.9 MW
Capacity
x 229
Renewable
8,199.3 MW
Capacity
x 2
Low carbon
2,240 MW
Capacity
View all competition assets by status.
View Bids
Help
Battery
Storage
Piclo Ref 1q8bxRN
1.2 MW
Ex. Active Power
1.2 MW
Im. Active Power
13.8 kV
Connection
-
Ex. Reactive Power
-
Im. Reactive Power
Operational
Status
Qualified for: PG&E Flex Resource Competition
Fairfax
Benicia
Bay Point
Oakley
Knightsen
Alhambra Valley
Brentwood
Orinda
Tiburon
Sausalito
Muir Beach
Stinson Beach
Alameda
Bayview District
Byron
Discovery Bay
Pacifica
Half Moon Bay
Woodside
Stanford
Ladera
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Flexibility Marketplace Architecture

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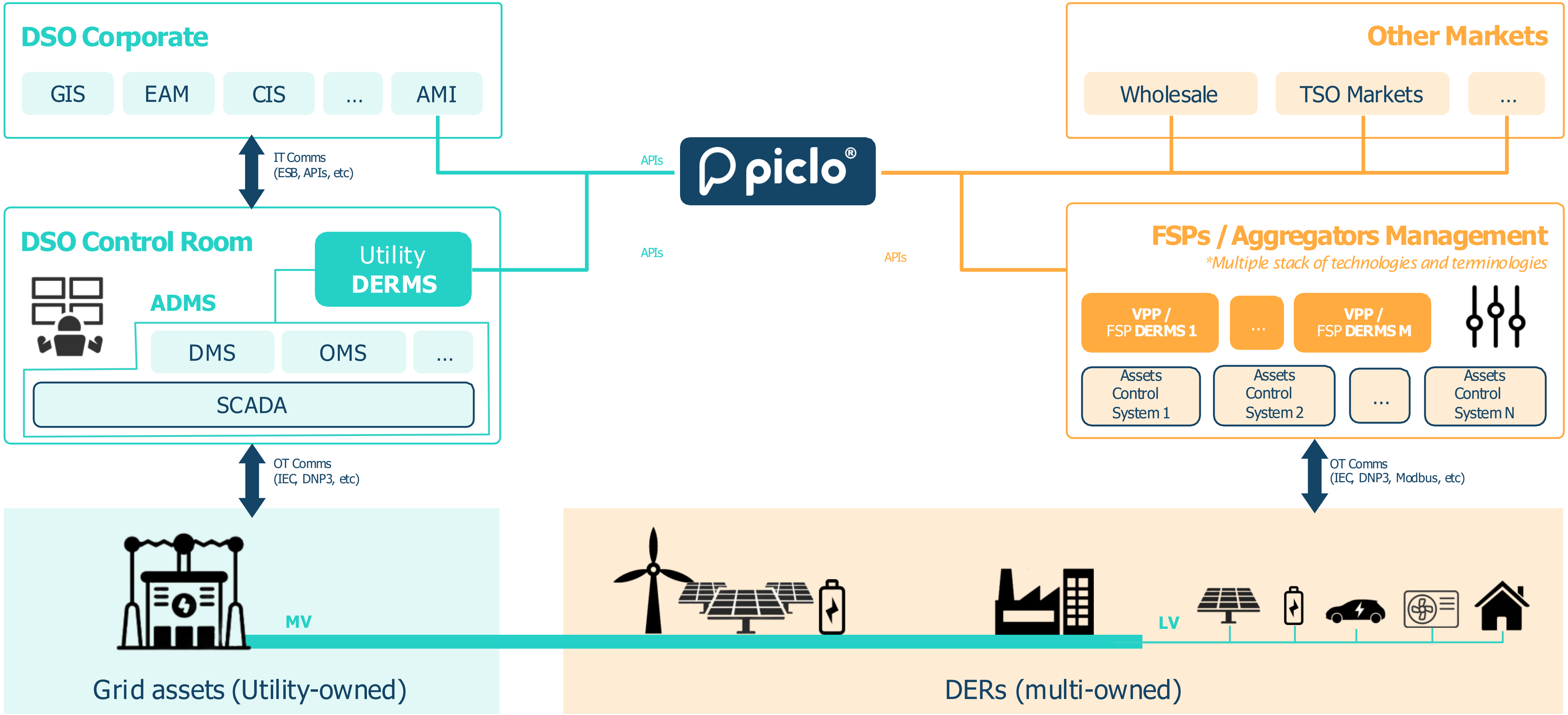
Flexibility Marketplace Architecture



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DSO flexibility Use Cases

Many teams working on DERs, distribution planning, and grid modernization can leverage flexibility for needs statements from real-time to multiple years in advance

Time Ahead of Need	**Long-term** 1 to 5 years	**Medium-term** 3 to 12 months	**Short-term** Intra-day to 3 months
Which Teams Utilize Piclo Marketplace	Grid Modernization, Customer/Provider Enablement		
	Distribution Planning, Program/Market Design	Delivery and Reliability, Market/Program Managers	Control Room, Grid Operations, Dispatch

Use Cases	• Infrastructure deferral
	  ○ Non-wires alternatives
	  ○ Bridge-to-wires
	• N-1 reliability /contingency
		• Planned maintenance
		• Constraint management
		• Resource adequacy
			• Outage restoration
			• Peak management
			• Voltage support

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End-to-end User Journey

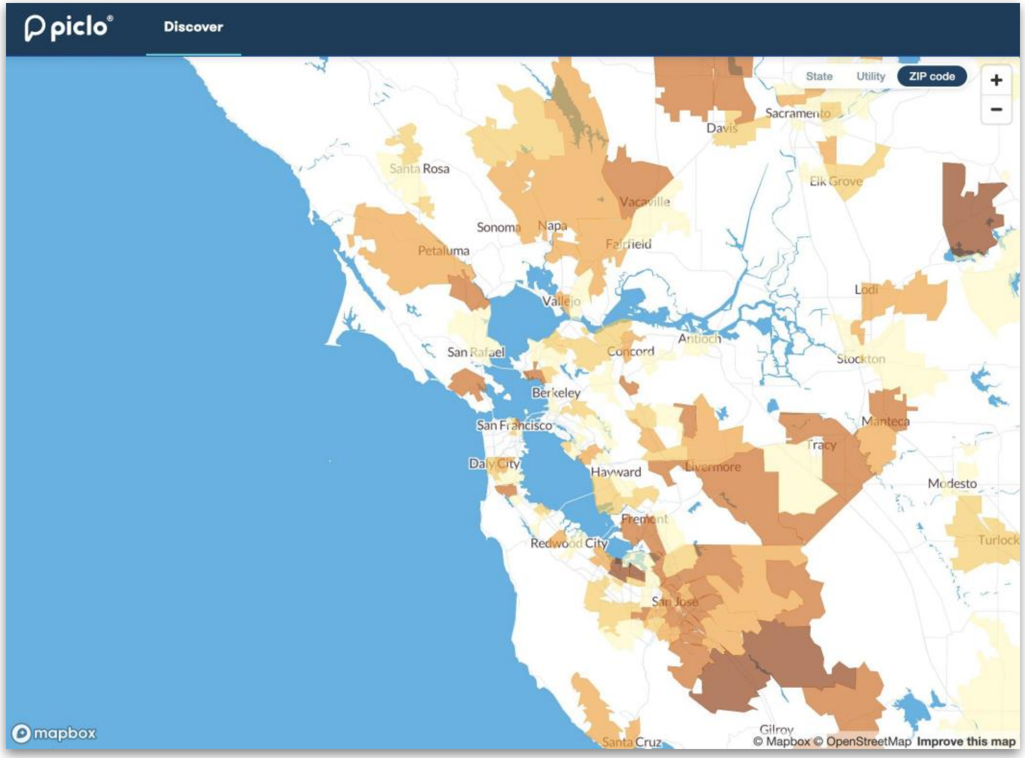
	1. Asset Registration	2. Market Open	3. Bid Decisions	4. Results & Contracts	5. Dispatch	6. M&V / Settlement
DSO Control System	Validate consent & customer info CIS adapter	Create competition (or via Piclo Web UI) → Competitions API	Fetch bids Accept / reject → Bids · Bid Decisions API	Confirm competition Fetch results → Competition Confirmation · Results	Send dispatch instruction → Dispatch Instruction API	Push meter readings Fetch payments → Meter Readings · Payments API
Piclo LFM Platform	Store assets Run qualification (CQ) Assets API	Publish offer to eligible FSPs Competitions · Bidding Opps	Auto-rank bids Surface for review Bids · Bid Decisions	Generate contracts Notify winners Results · Obligations	Relay to FSP via UI · Email · Webhook · API Dispatch Instruction (+ Webhook)	Run settlement calculation Meter Readings · Payments
FSP / Aggregator	Create & manage flex assets → Assets API	Fetch opportunities Submit bids → Bidding Opps · Bids API	*(awaiting decision)*	View results Fetch obligations → Results · Obligations	Receive dispatch Accept / reject → Dispatch Instruction API	View settlement Fetch payments → Payments API

Time →

Flexibility Marketplaces deliver value to all stakeholders

Marketplaces **unlock silos**, compounding benefits across multiple use cases:

- DSO flexibility
- Resource Adequacy
- Load modification
- BYOC model for Data Centers
- Data Clean Room for VPPs
- Value Stacking
- Anti-gaming monitoring
- TSO-DSO coordination



...ultimately benefiting **all customers**

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TSO-DSO Coordination Case Study

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Case Study: Local Constraint Market with NESO

NESO is Great Britain's Transmission System Operator (TSO).

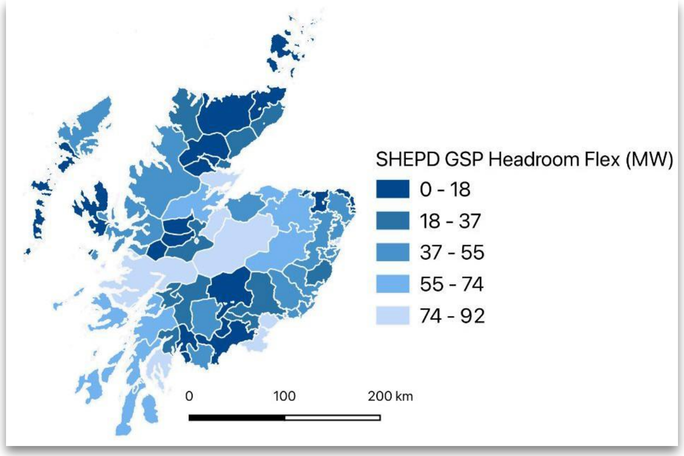
Piclo runs the Local Constraint Market (LCM) for NESO: a market for managing transmission constraints from large Scottish wind generators by activating demand turn-up on local distribution networks.

Key Features & Impact:

- **End-to-End Market Integration** - from procurement to settlement, with automated order book generation
- **Rolling Day-Ahead & Intraday Market** - 30-minute settlement periods
- **Automated Transactions & Dispatch** - flex dispatch via API/email, with integrated metering & invoicing
- **TSO/DSO Coordination**- bid volumes adjusted based on network capacity headroom thresholds provided from Scottish DSOs

Currently operating with static 100kW limits/GSP in place, with a dynamic operating envelope approach under development.

Platform is live within the NESO control room



Distribution network capacity headroom for participation in NESO LCM.

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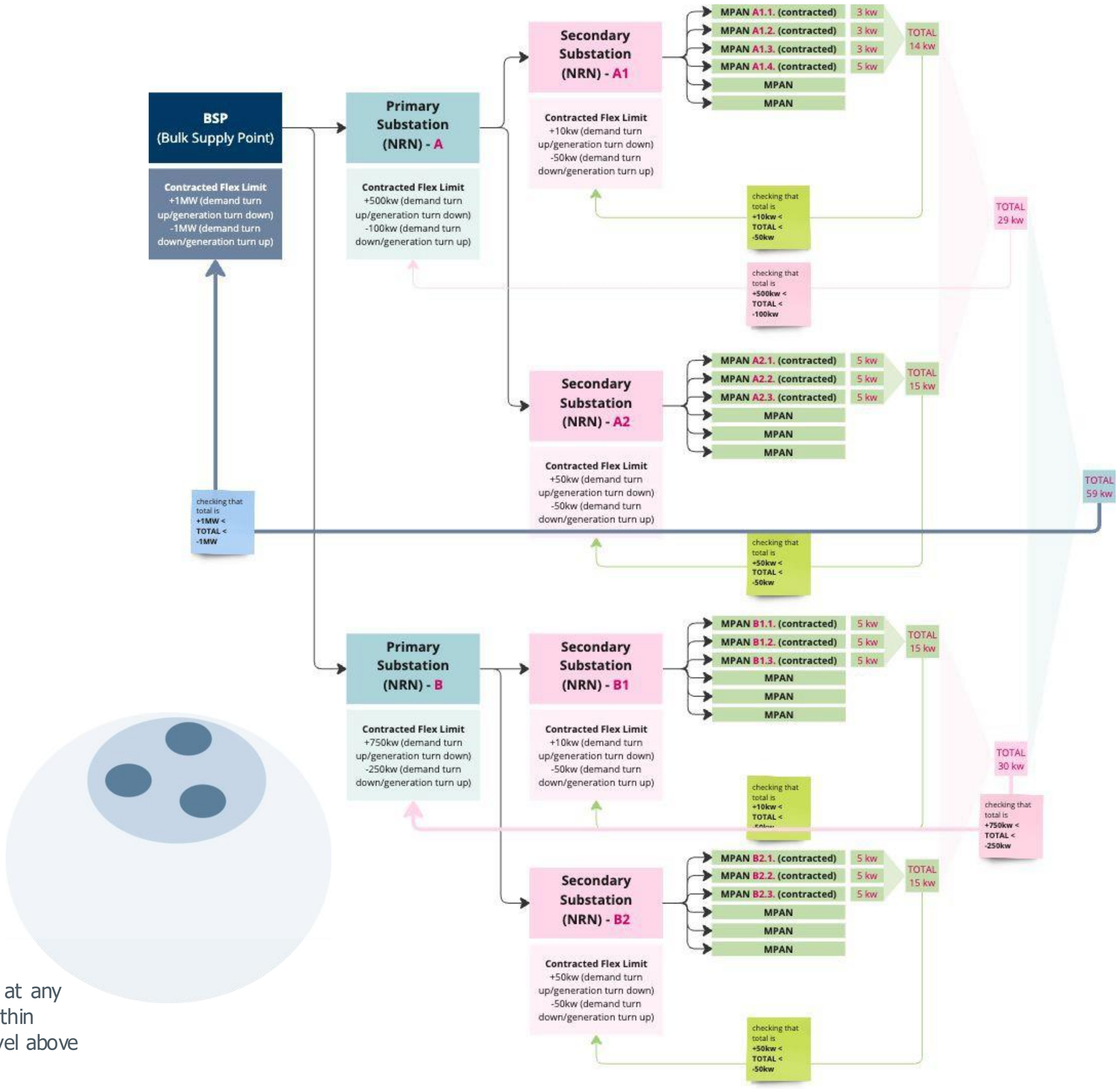
Network Capacity Envelopes

- The concept of capacity envelopes insures network integrity by limiting bid volumes at different levels of the network
- Modelled network headroom data is provided by DSOs and queried by Piclo to prevent LCM actions exceeding network limits



Network capacity at any level is 'nested' within capacity at the level above

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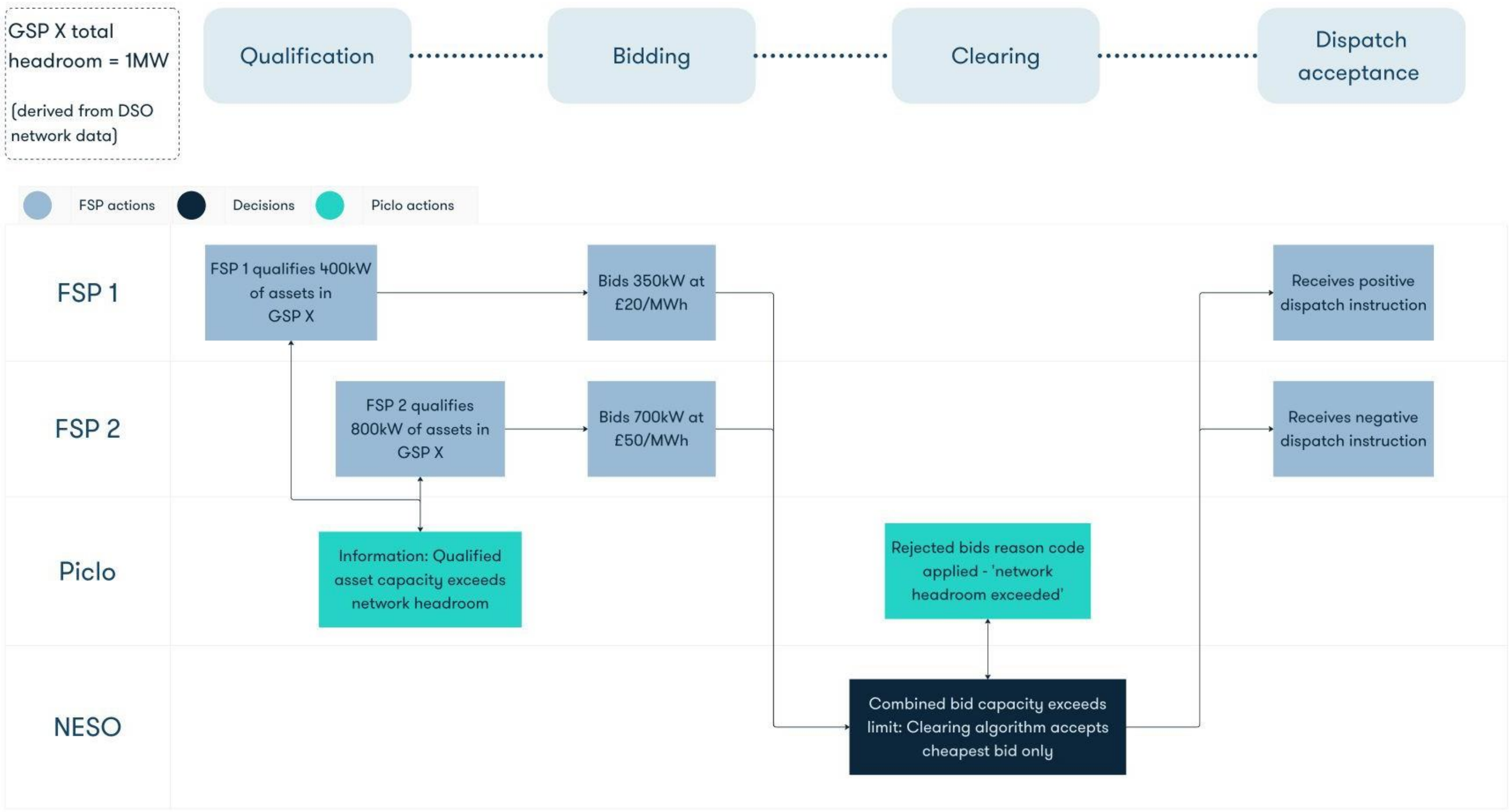
Worked Example - Sunny Day Scenario



Final remarks

- Independent marketplaces are proven globally
- Marketplaces give DER providers an incentive to share data
- Technical architecture unlocks data and organisational silos
- TSO/DSO coordination is off-the-shelf capability
- Drives value to all stakeholders: supporting affordability for all customers

James Johnston
CEO and Cofounder
james@piclo.com

Open Discussion: Developing an Operational TSO-DSO Coordination Framework

Possible Discussion Questions to Consider:

- What gaps currently exist in integrating demand-side DER data from multiple DER providers and how can they be addressed?
- Where should stakeholders focus future coordination efforts for DERs that provide both bulk system and distribution system services?
- How can TSO-DSO operational coordination frameworks prioritize maintaing or improving overall grid reliability?
- How can stakeholders reduce the risk of conflicting DER dispatch commitments?

Open Discussion: Aligning DER Modeling and Forecasting Integration

Possible Discussion Questions to Consider:

- How can or should the roles and responsibilities of DER participants such as DSOs, LSEs, Scheduling Coordinators, and Aggregators be further developed to support effective DER coordination?
- How can participating entities better align forecasting methods, assumptions, and DER modeling to improve DER information exhanges across entities?

Closing Remarks & Next Steps

Energy Division Staff

Next Steps, Workshop Report, and Ongoing Collaboration

- Review outcomes of coordination discussion
- Discuss near-term priorities and potential future collaboration mechanisms
- Discuss joint CAISO-IOU workshop report and alignment with DSO orchestration framework being developed