July 29, 2026

California Energy Commission
715 P Street,
Sacramento, CA 9581
Via Electronic Filing

CEC Docket 22-OII-01: Clean Coalition Comments on July 15 Workshop on DER AMI Data

Dear Chair Hochschild, Vice Chair Gunda, California Energy Commission Commissioners, and Staff,

Collectively, the workshop presentations demonstrate that California increasingly possesses the data, analytical tools, and operational experience needed to identify what distributed energy resources can do, when they can perform, and where they can provide the greatest value. The remaining challenge is to integrate that information into a coordinated planning framework that evaluates generation, load flexibility, distribution infrastructure, transmission investment, resilience, and other public benefits together. The CEC should use this proceeding to advance an iterative, locationally informed planning process that treats clean local resources as core planning options and seeks to minimize total system cost while maximizing net system value.

These comments focus on four overarching conclusions from the workshop: (1) the need for cleaned and decision-grade DER data, (2) the importance of moving AMI analysis beyond forecasting into planning and procurement, (3) the need to include FTM DER and flexible load as core planning options, and (4) the value of integrated, locationally informed planning that considers energy, infrastructure, reliability, resilience, and other material benefits together.

The Clean Coalition is a nonprofit organization whose mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise. The Clean Coalition drives policy innovation to remove barriers to procurement and interconnection of distributed energy resources ("DER") — such as local renewables, demand response, and energy storage — and we establish market mechanisms that realize the full potential of integrating these solutions for optimized economic, environmental, and resilience benefits. The Clean Coalition also collaborates with utilities, municipalities, property owners, and other stakeholders to create near-term deployment opportunities that prove the unparalleled benefits of local renewables and other DER.

The Workshop Demonstrates the Need for Integrated and Locationally Informed Grid Planning

The workshop presentations addressed AMI analytics, demand flexibility, front-of-the-meter (FTM DER), distribution needs, Resource Adequacy (RA), and community resilience as largely distinct subjects. Taken together, however, they reveal a common planning challenge. California increasingly possesses the technology and data needed to shape load, deploy generation and storage close to demand, support distribution operations, and improve resilience. Yet those capabilities are not consistently evaluated alongside generation, transmission, and distribution infrastructure when the state selects its future resource portfolio.[1]

Separately optimizing generation procurement, transmission development, and distribution investment does not necessarily minimize total system cost. Distribution planning remains largely downstream from demand forecasting, Integrated Resource Planning, and transmission planning, while FTM DER and other local solutions are not consistently included as candidate resources in statewide

[1] https://clean-coalition.org/news/energy-tetris-part-1-effectively-managing-the-grid-of-the-21st-century/

portfolio analysis. By the time a local need is identified, broader portfolio and infrastructure decisions may already have foreclosed the most valuable or cost-effective DER alternatives.

The CEC should therefore advance an iterative, co-optimized planning process that evaluates supply, flexible demand, distributed resources, transmission, distribution infrastructure, resilience, and other material constraints together.[2] Under this approach, AMI and DER data would not merely refine a forecast. They would identify when and where flexible load and local resources can alter infrastructure needs; those findings would inform resource and transmission planning; and the resulting system consequences would feed back into subsequent portfolio analysis.

1. **The CEC Should Establish Cleaned, Enriched, and Decision-Grade Statewide DER Data Infrastructure**

The workshop demonstrated that California's challenge is no longer simply obtaining more energy data. The CEC already receives enormous volumes of AMI and related information, but raw records do not automatically provide usable planning insight. To support forecasting, procurement, infrastructure planning, resilience, and equitable program design, the state needs data that are consistently validated, cleaned, standardized, enriched, documented, and converted into decision-grade analytical outputs. Recurve's presentation illustrated both the value of the CEC's existing data and the barriers to unlocking it. Recurve explained that the residential AMI data alone total approximately 250 terabytes, originate from multiple utilities with overlapping service territories, and contain limited site characteristics beyond information such as address, solar status, and rate code. The size and fragmentation of the underlying data make repeated ad hoc analysis costly and create a need for precomputed, standardized metrics that can be reused across studies and planning processes.

Recurve demonstrated how data enrichment can convert these raw records into significantly more useful information. The methods presented included address normalization, matching gas and electric meters across utilities, classifying single-family and multifamily housing, and incorporating external information such as county, census tract, climate and forecast zones, income, disadvantaged-community status, and manufactured-housing status. Recurve also described the validation, cleanup, structuring, end-use detection, disaggregation, valuation, measurement, targeting, and forecasting functions needed to transform disparate utility and third-party records into trusted analytical outputs.

The workshop presentations provided concrete examples of the resulting value. Recurve used enriched meter data to detect central air conditioning, electric and gas space heating, and gas water heating, and to estimate end-use saturation by climate zone, county, ZIP code, and census tract. These results were broadly consistent with survey-based estimates but were more geographically granular and current. Recurve also demonstrated the ability to identify highly specific populations with unmet cooling needs and target households most likely to benefit from electrification programs. These examples show that enriched data can support not only aggregate forecasting, but also locational planning, equity analysis, program targeting, and evaluation of customer impacts.

CEC staff's EV analysis similarly demonstrates the value of converting raw meter data into standardized and usable information. By combining utility interval data with vehicle-registration records and applying charging-detection methods, the CEC narrowed a statewide population of 1.89 million registered EVs to approximately 468,000 households with detectable Level 2 home charging. The analysis then characterized differences in charging behavior, rate enrollment, housing type, geography, and timing.

[2] https://clean-coalition.org/news/energy-tetris-part-2-a-practical-blueprint-for-integrated-grid-planning-in-california/

These findings would not have been available from vehicle-registration totals or undifferentiated AMI records alone.

The residential PV presentation provides another example of why an integrated data infrastructure is necessary. Verdant Associates recommended incorporating actual PV generation data where available and using EV and heat-pump detection to better distinguish the drivers of changes in customer consumption following PV adoption. That recommendation highlights a broader need to connect AMI data with DER system characteristics, program participation, rate information, building attributes, and other end-use indicators. Without those linkages, analysts may observe a change in net load without being able to determine whether it results from solar production, electrification, storage operation, behavioral change, or another cause.

The CEC's existing data warehouse provides an important foundation for this work. ***The CEC should use that infrastructure not merely to retain raw utility submissions, but to maintain cleaned, validated, enriched, and documented datasets that can support recurring analysis across programs, proceedings, and planning cycles.*** Preserving reusable data products, methodologies, metadata, and standardized outputs would allow future analyses to build cumulatively on prior work rather than requiring each study to reconstruct the same underlying information.

The CEC should therefore establish a statewide DER data infrastructure that integrates, as appropriate:

- Privacy-protected AMI and load-shape information,
- DER technology, capacity, configuration, and operational characteristics,
- Interconnection and project-status information,
- Rate and program participation,
- Building and property characteristics,
- Climate, demographic, and community indicators,
- Geographic and appropriate grid-location identifiers,
- End-use detection and flexible-load characteristics, and
- Measured program impacts and standardized performance metrics.

The database should include both customer-side and FTM DER information. The CEC's FTM DER overview identified several sources that currently provide only portions of the relevant picture, including QFER supply data, utility WDAT interconnection-queue reports, CPUC resource-tracking reports, and DGStats. These sources serve different purposes, use different definitions, and do not necessarily allow planners to follow a project consistently from proposal through interconnection, procurement, operation, and performance. A more coordinated data structure could clarify how much FTM DER is proposed, contracted, interconnected, operational, and available to provide particular services.

This distinction is especially important because the workshop showed a recurring gap between authorized, procured, and delivered capacity. PG&E emphasized that announced or authorized megawatts cannot be treated as equivalent to operating resources that reliably appear at the expected location and time. Decision-grade DER infrastructure should therefore preserve project status and performance distinctions rather than reporting nameplate capacity alone. Standardized status categories and identifiers would improve the CEC's ability to evaluate program delivery, development timelines, interconnection outcomes, and the reliability of different procurement pathways.

The objective should not be to create a single unrestricted repository of customer-level records. Different users and purposes will require different access tiers, levels of aggregation, confidentiality protections, and data-use agreements. However, privacy protection should be incorporated into the design of useful data products rather than treated as a reason to limit the state to raw internal records or broad statewide summaries. Standardized, privacy-protected outputs could support the CEC, CPUC, CAISO, utilities, LSEs, local and Tribal governments, researchers, and other authorized users without disclosing customer-identifiable information.

The CEC should also ensure that the infrastructure produces decision-grade interfaces, not merely downloadable datasets. Relevant outputs could include standardized load shapes, end-use and DER saturation estimates, flexible-load potential, adoption and performance metrics, geographic opportunity analyses, and documented methodologies. These outputs should be designed for incorporation into demand forecasting, Integrated Resource Planning, distribution planning, transmission analysis, LSE procurement, resilience planning, and local energy initiatives.

The workshop demonstrated that the analytical components already exist. The CEC and its partners can detect DER and end-use behavior, enrich records with site and community characteristics, evaluate program impacts, and produce geographically granular insights. The next step is to institutionalize those capabilities so that cleaned and enriched data become durable planning infrastructure rather than the temporary product of individual research projects.

2. AMI Analysis Should Inform Procurement and Infrastructure Planning, Not Only Forecasting

The workshop demonstrated that AMI data can reveal not only how much electricity customers use, but when, where, and for what purposes they use it. These capabilities should improve the CEC's demand forecasts, but their value should not end with the production of a more accurate statewide load curve. AMI-derived findings should also inform the design and geographic targeting of demand-flexibility programs, DER procurement, distribution investment, and the assumptions used in resource and transmission planning.

CEC staff's analysis of residential electric vehicle charging illustrates this broader opportunity. The analysis identified approximately 468,000 homes with detectable Level 2 charging and found meaningful differences in charging behavior across households, rates, utilities, and days. On average, the additional load associated with EV ownership generally peaks overnight rather than during the 4:00–9:00 p.m. period. Yet the analysis also identified several distinct charging patterns, including an afternoon pattern that occurs on approximately 10 percent of detected charging days and is particularly relevant to load shifting. Charging behavior also changes with system conditions: the share of homes charging increased on the September 5, 2024 peak day, including a higher prevalence of afternoon charging, while charging declined on the April 20, 2024 solar-curtailment day.

CEC staff appropriately explained that these findings will inform EV load forecasting, demand scenarios, demand-flexibility analysis, and the state's Load-Shift Goal. The analysis should also be used to determine where more active intervention would produce the greatest value. For example, it can help identify locations where afternoon charging contributes to a feeder or substation peak, where additional daytime charging could absorb otherwise curtailed renewable production, and where overnight charging may be accommodated without substantial infrastructure expansion. Rather than applying a uniform EV load shape or program design statewide, the CEC should support geographically differentiated strategies based on observed charging patterns and local grid conditions.

This distinction is important because flexible load should not be treated solely as an adjustment to the amount of demand that planners expect to serve. Properly measured and managed, it can alter when infrastructure is needed, increase use of existing grid capacity, and reduce the peak demands that drive generation, transmission, and distribution investments. AMI analysis can help distinguish load that is already occurring outside constrained periods from load that remains available for cost-effective shifting. It can also provide the empirical basis for estimating program participation, persistence, coincidence with grid needs, and the achievable—not merely theoretical—contribution of managed charging and other flexible loads.

Recurve's presentation further demonstrated that these capabilities extend well beyond EV charging. Recurve described methods for cleaning and enriching the CEC's meter data, disaggregating heating, cooling, and temperature-independent consumption, detecting major end uses, and calculating load-shape and program-impact metrics at the individual-meter level. These analyses can produce end-use saturation estimates by climate zone, county, ZIP code, and census tract that are more geographically granular and current than periodic survey results. Recurve also demonstrated that measured program results can be used to forecast the energy, bill, greenhouse-gas, and grid impacts of electrification across millions of California households.

These capabilities can support a more strategic approach to electrification and demand flexibility. The location and timing of heating, cooling, water-heating, and vehicle-charging loads affect whether electrification can be accommodated efficiently or will trigger substantial infrastructure investment. The same data used to forecast statewide electrification demand can help identify where flexible operation, targeted efficiency, local generation, storage, or a combination of resources would reduce the cost of serving that demand. The CEC should therefore develop locational outputs that can be incorporated into utility distribution planning and LSE program and procurement decisions, rather than limiting the analysis to broad forecast zones or statewide totals.

The residential PV presentation provides another example of why DER and AMI analysis must inform more than the forecast. Verdant Associates found that customers may change their electricity consumption following PV installation and recommended incorporating those effects into CEC forecasting. The presentation also recommended adding actual PV production data and using EV and heat-pump detection to better identify the causes of observed consumption changes. These findings demonstrate that DER adoption does not simply subtract a fixed production profile from otherwise unchanged customer demand. The adoption of solar, storage, EVs, heat pumps, and rate-responsive technologies can change gross consumption, net demand, the timing of grid imports and exports, and customers' responsiveness to price and program signals.

Planning should account for those interactions directly. Treating gross load, flexible load, DER production, and customer behavior as separate assumptions developed through separate processes risks obscuring the combinations that can most effectively reduce system costs. An integrated analysis could instead evaluate whether a location experiencing new electrification load would be most efficiently served through infrastructure expansion, managed load, local generation, storage, or a coordinated portfolio of those resources.

The CEC should establish a recurring process for converting AMI-derived findings into actionable planning inputs. At a minimum, this process should:

1. Identify the timing, location, and end-use characteristics of loads with meaningful flexibility,
2. Estimate achievable load modification based on observed behavior and measured program performance,
3. Translate those findings into geographically appropriate program, procurement, and infrastructure

assumptions,

4. Provide standardized outputs that can be used in CPUC resource and distribution planning, LSE procurement, and CAISO transmission analysis, and
5. Incorporate the resulting infrastructure and system effects into subsequent CEC demand forecasts and scenarios.

The objective should be an iterative planning process rather than a one-directional transfer of an aggregate forecast. AMI analysis should identify where flexible load and DER can change local needs; distribution and transmission analysis should assess the infrastructure consequences; and those findings should then inform the next portfolio and demand analysis. This feedback loop would allow California to plan around the capabilities of modern loads and DERs rather than assuming that all forecast demand must be served through additional generation and wires infrastructure.

3. FTM DER Should Be Included as a Core Statewide Planning Option

The CEC's presentation established that FTM DER includes distribution-connected resources that deliver their output directly to the grid and are not limited by an individual customer's load. The presentation identified CAISO market participation, feed-in tariffs, and virtual net energy metering as existing pathways for these resources. This definitional and deployment review provides an important foundation, but the CEC's analysis should now progress from identifying existing FTM DER to evaluating its potential role in California's future resource portfolio.

FTM DER is not consistently modeled as a candidate resource in statewide portfolio planning. As a result, planning processes may select transmission-connected generation and associated infrastructure without first determining whether strategically located distribution-connected generation, storage, or microgrids could meet the same energy and reliability needs at a lower total system cost. An optimization cannot select a resource that is excluded from consideration.

The workshop presentations demonstrated why that omission matters. WestLight explained that current procurement criteria, including offer price and Full Capacity Deliverability Status, naturally favor larger transmission-connected projects. PG&E's presentation also showed that FTM DER has performed well where resources were tied to a clearly identified local grid need and where location, funding, timing, and interconnection were sufficiently certain. Eddy Energy cited CPUC Energy Storage procurement studies showing the value of third-party-owned FTM energy storage, which produced a benefit-cost ratio of 2.5, compared to 1.6 for the next best transmission-connected resource. These findings support evaluating FTM DER based on the complete set of services and infrastructure effects it can provide, rather than only those values recognized through existing bulk-system procurement criteria.

The CEC should therefore include realistic FTM DER portfolios in the IEPR, SB 100, and other relevant scenario analyses. These portfolios should include distribution-connected solar, standalone and paired storage, community microgrids, and other qualifying local resources, with assumptions reflecting their location, operating capabilities, development timelines, interconnection costs, and potential effects on transmission and distribution investment. The analysis should compare the total cost and performance of portfolios with and without strategic FTM DER deployment.

Including FTM DER does not presume that local resources should replace every transmission-connected resource or conventional grid investment. It ensures only that California evaluates all viable options before committing ratepayers to a particular resource and infrastructure pathway. Without that comparison, the state cannot determine whether its selected portfolio minimizes total system cost or maximizes net system value.

4. California Needs Strategic, Locational Procurement Based on the Full DER Value Stack

PG&E's presentation described the Distribution Investment Deferral Framework (DIDF) as a sustained effort to procure FTM DER through a locational planning process. DIDF disaggregated the IEPR forecast to the circuit level, identified distribution deficiencies through the Grid Needs Assessment, ranked potential deferral opportunities, and solicited DER to meet selected needs. The underlying concept remains important: DER can serve as a non-wires alternative where strategically located generation, storage, or flexible load can defer or avoid a conventional distribution investment. The CPUC continues to describe DIDF in precisely those terms—as a process for identifying opportunities for competitively sourced DER to defer or avoid utility distribution capital investments.

The limited number of projects delivered through DIDF should not be interpreted as evidence that DER deferral is ineffective. DIDF tested that concept through an unusually narrow procurement structure that made successful project development difficult. Opportunities were defined around highly specific locations, operating requirements, need dates, and eligibility criteria. Developers were asked to construct projects for needs that could change or disappear during development, frequently on timelines that did not align with permitting, interconnection, financing, and construction. At the same time, the procurement generally compensated only the temporary distribution-deferral service, without allowing the project to rely on the broader energy, capacity, renewable-energy, resilience, or other compatible values needed to support long-term financing.

PG&E's own presentation confirms several of these structural limitations. PG&E explained that DIDF procurement was restricted to distribution-capacity value and excluded RA, energy, and renewable-energy credits. It also noted that changes in forecasts affected the durability of identified deferral opportunities and that aligning DER development timelines with utility need dates proved difficult. Those findings do not show that the DER could not provide the required grid service. They show that a resource is unlikely to be financeable when it must be developed for a narrowly defined and potentially temporary need, cannot rely on a complete value stack, and bears the risk that the utility may later revise or withdraw the opportunity. The implementation also gave utilities substantial ability to exit opportunities when planning assumptions changed, while developers bore much of the cost and development risk associated with responding to a solicitation. In at least one PG&E procurement, the utility withdrew from a project based on generalized load-growth considerations without demonstrating that the identified DER was no longer needed to defer the relevant upgrade.[3] A deferral framework cannot create a durable market where the utility can withdraw the underlying need based on revised internal assumptions without a transparent showing, while the developer remains responsible for sunk development and interconnection costs.

Most importantly, the projects that did become operational demonstrate that DER deferral can work. Two SCE battery projects successfully avoided planned transformer upgrades and produced approximately $7.5 million in ratepayer savings.[4] Those results are more probative of the technical and economic validity of DER deferral than the number of highly constrained solicitations that failed to produce contracts. Where the need was sufficiently clear, the resource was deployable, and the project reached operation, the DER performed the intended function and avoided conventional infrastructure costs.

The correct lesson from DIDF is therefore not that locational DER procurement should be abandoned. It is that locational procurement must be designed around project deliverability and the full

[3] See the CPUC's 2025 California Grid Modernization Report.
[4] CONFIDENTIAL DER PAYMENTS REPORT OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) at p. A-1 – A3.

value a DER can provide. A viable framework should identify needs early enough to accommodate realistic development timelines, allow projects to combine compatible revenues, provide sufficient contract duration and certainty for financing, and allocate forecast and cancellation risk fairly between utilities and developers.

Future strategic procurement should also move beyond the binary question of whether one DER can replace one predetermined wires project. A local portfolio may combine FTM storage, BTM resources, managed charging, demand response, advanced inverter functions, and targeted efficiency to reduce or reshape the same need. The relevant comparison should be between the total cost and performance of that portfolio and the complete cost of the conventional infrastructure alternative—not merely the price of one short-duration service offered through a narrowly defined solicitation.

AMI and enriched DER data can make this approach more durable than DIDF. Improved information about hourly load, end uses, adoption patterns, flexibility, and local growth can identify needs earlier and reduce the likelihood that opportunities disappear after procurement begins. The CEC can help identify locations where several values overlap, including:

- Forecast load growth and limited distribution headroom,
- Local or system capacity needs,
- High outage exposure or critical facilities,
- Substantial flexible-load potential,
- Renewable curtailment or charging opportunities,
- Suitable locations for local generation or storage, and
- Equity, affordability, or resilience priorities.

Projects in these locations should be evaluated based on their full compatible value stack, including energy, capacity, distribution support, transmission effects, resilience, environmental benefits, and speed to deployment. A resource should not be required to survive on one temporary avoided-cost payment merely because the relevant values are administered through different planning processes or regulatory jurisdictions.

The CEC should therefore recommend a successor approach to locational DER procurement that preserves the core principle of distribution deferral while correcting the limitations exposed by DIDF. At minimum, that approach should:

1. Identify candidate locations earlier and through transparent, decision-grade data,
2. Provide realistic procurement, interconnection, permitting, and construction timelines,
3. Permit compatible value stacking rather than restricting projects to a single distribution service,
4. Use contract terms long enough to support project financing,
5. Require transparent evidence before a utility may cancel or withdraw an identified need,
6. Compensate developers appropriately where utility forecast changes strand reasonable development expenditures,
7. Evaluate portfolios of supply- and demand-side DER against wires alternatives, and
8. Track avoided upgrades, delivered performance, and actual ratepayer savings.

PG&E correctly observed that DIDF created valuable transparency into distribution planning. California should preserve and build upon that transparency. The appropriate response to a procurement structure that was too narrow to produce a robust market is not to return to wires-only planning, but to create a more workable framework in which DER can compete fairly against conventional infrastructure and be procured where they reduce total system cost.

5. **Capacity Recognition Should Reflect Verifiable Supply, Load-Modification, and Local Reliability Contributions**

The workshop identified a fundamental question for distribution-connected resources: whether California's capacity framework recognizes the reliability contribution a resource actually makes at the relevant grid interface. WestLight explained that current procurement evaluation emphasizes offer price, RA portfolio needs, and Full Capacity Deliverability Status, naturally favoring larger transmission-connected projects. WestLight proposed comparing supply-side RA value with demand-side or load-modification value and examining whether distribution-connected resources can reduce the load that must otherwise be served through the transmission system.

RA exists to ensure that sufficient resources are available when and where needed for reliable grid operation, while CAISO deliverability requirements determine whether supply-side capacity can serve load under stressed transmission conditions. Those objectives should be preserved. However, the current framework should not assume that transmission delivery is the only way a resource can reduce the capacity needed to serve customers.

A strategically located FTM resource may generate or discharge directly onto the distribution system near the load it serves. Where the resource's output is absorbed within the local distribution area and measurably reduces imports through the relevant substation or transmission interface, the system does not need an equivalent quantity of remote generation and transmission capacity to serve that load during those hours. From a planning perspective, supplying one megawatt locally can have the same net effect at the interface as reducing load by one megawatt: both reduce the amount of power that must be delivered into the area.

The critical question should therefore be the resource's verifiable effect, not merely whether it is categorized as generation or load. That effect could be established through:

- Historical and forecast load conditions at the relevant interface,
- Power-flow and hosting-capacity analysis,
- Metering and telemetry,
- Operating limits or export controls where needed,
- Demonstrated coincidence with RA or local-reliability hours,
- Availability and performance requirements, and
- Periodic verification that the resource continues to reduce the relevant planning need.

This would not require treating every distribution-connected generator as load modification or bypassing reliability review. PG&E emphasized during the workshop that supply-side deliverability serves an important reliability function and cautioned against reclassifying generation solely to avoid that process. The appropriate response is not an administrative relabeling of resources, but a performance-based framework that distinguishes among the services they provide.

At least three separate contributions should be recognized:

1. Supply-side capacity consists of generation or storage demonstrated to be deliverable and available under applicable RA requirements.
2. Load modification consists of a dependable and measurable reduction in the load forecast or capacity obligation that would otherwise have to be served.
3. Local reliability support consists of a resource's ability to reduce loading, maintain local service, preserve distribution headroom, support voltage, or meet another defined need at a particular feeder, substation, or local area.

These contributions may overlap, but they are not identical. A resource should not receive duplicative capacity credit for the same performance. At the same time, California should not ignore a measurable local or system benefit merely because it does not fit within the conventional supply-side RA pathway.

The distinction is particularly important for distribution-connected storage. Storage located near load may discharge during the hours that establish system or local capacity needs, reduce imports through a constrained interface, and avoid or delay additional infrastructure. If its charging and discharging patterns are coordinated so that charging does not create a new constraint, its dependable net-load reduction can provide a reliability contribution comparable to capacity delivered from outside the area. WestLight specifically identified strategically placed distribution-connected storage, preservation of distribution headroom, local reliability, and speed to power as issues the CEC should evaluate.

Local RA requirements are intended to ensure that sufficient capacity is available within constrained local areas to satisfy applicable reliability criteria. Yet the present framework may not fully capture the value of resources that reduce the amount of power that must enter the constrained area in the first place. A resource located downstream of the relevant transmission constraint may provide especially strong local value where its output reliably serves local demand during the hours driving that requirement.

The CEC should therefore evaluate an interface-based capacity methodology for FTM DER and flexible load. The analysis should determine:

1. The feeder, substation, local-capacity area, or transmission interface at which the resource changes net demand,
2. The hours and conditions during which the reduction is dependable,
3. Whether output is expected to remain within the local distribution area or increase flow across another constrained interface,
4. The operating, metering, and verification requirements necessary to preserve that contribution,
5. Whether the resulting reduction should be reflected through supply-side RA, load modification, local capacity credit, or another planning mechanism, and
6. How to prevent double counting while allowing compensation for distinct distribution, energy, resilience, or ancillary services.

The CEC is well positioned to support this work because AMI and enriched grid data can reveal whether local generation or storage actually coincides with local consumption and reduces imports during reliability hours. Rather than presuming that all FTM output either requires full transmission deliverability or provides no capacity value, California should measure the physical effect of the resource and recognize the dependable contribution it makes.

Capacity recognition should follow verifiable performance at the relevant grid interface. Where a distribution-connected resource reliably serves local load and reduces the amount of capacity that must be delivered through a constrained transmission or distribution interface, that reduction should be recognized in planning and procurement. The CEC should work with the CPUC and CAISO to develop a transparent methodology that preserves reliability standards, prevents double counting, and provides an efficient pathway for FTM DER and flexible load to receive capacity recognition commensurate with their demonstrated contribution.

6. **Community Microgrids and Distribution-Sited Storage Should Be Planned as Integrated Local Portfolios**

The Redwood Coast Airport Microgrid demonstrated that local generation, storage, controls, wholesale participation, and islanding can be coordinated to provide both ordinary grid services and community resilience. During a major earthquake-related outage, the project served the airport and Coast Guard station for 15 of 16 outage hours under unusually difficult operating conditions. PG&E and WestLight likewise identified distribution-sited storage as capable of addressing defined local grid needs, preserving distribution headroom, and improving reliability.

The CEC should therefore evaluate community microgrids and distribution-sited storage as integrated local portfolios rather than isolated technologies. AMI, outage, critical-facility, load-growth, and grid-constraint data should be used to identify locations where coordinated portfolios of generation, storage, flexible load, and controls can provide the greatest total system and community value.

7. Resilience and Other Material Risks Should Be Incorporated into Portfolio Optimization

The Redwood Coast presentation quantified substantial resilience value while also identifying additional benefits that were not fully captured by existing market revenues. It further showed that wholesale dispatch affected the battery's state of charge when the outage began, illustrating that resilience depends on project sizing, operating rules, and dispatch priorities—not merely the presence of storage.

Resilience should therefore be incorporated before a portfolio is selected, rather than treated as an incidental benefit afterward. The CEC should include outage exposure, critical-facility needs, customer interruption costs, geographic isolation, wildfire and climate risk, permitting feasibility, and other material considerations when comparing local DER portfolios with conventional resource and infrastructure alternatives.

8. The CEC Should Produce Standardized Outputs and an Iterative Feedback Loop Across Planning Processes

The workshop showed that the CEC can detect charging behavior, identify end uses, enrich customer and site data, measure DER impacts, and characterize FTM DER deployment. The value of that work will depend on whether the resulting information can be incorporated into other planning and procurement processes.

The CEC should produce standardized, decision-grade outputs suitable for use in CPUC resource and distribution planning, CAISO transmission planning, LSE procurement, utility investment analysis, and local and Tribal energy planning. Distribution and transmission findings should then feed back into subsequent CEC forecasts and scenarios so that planning becomes iterative rather than a one-way transfer of aggregate demand assumptions.

Conclusion

The Clean Coalition appreciates the opportunity to submit these comments. The July 15 workshop demonstrated that California increasingly possesses the data, analytical capabilities, and operational experience needed to deploy DER more strategically. The CEC should now institutionalize those capabilities through decision-grade data infrastructure and an iterative, locationally informed planning framework that allows flexible load, FTM DER, community microgrids, and other clean local resources to compete based on their full value to the grid, ratepayers, and communities.

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