BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	Rulemaking 21-06-017 Filed June 24, 2021

CLEAN COALITION COMMENTS ON ASSIGNED COMMISSIONER'S RULING ISSUING QUESTIONS ON THE ELECTRIFICATION IMPACT STUDY PART 2 FINAL REPORTS

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I. INTRODUCTION

Pursuant to Rule 6.2 of the Rules of Practice and procedure of the California Public Utilities Commission ("the Commission"), the Clean Coalition respectfully submits these comments on the *Assigned Commissioner's Ruling Issuing Questions on the Electrification Impact Study* ("EIS") *Part 2 Final Reports*, issued at the Commission on May 8, 2026.

The EIS Part 2 studies confirm that load flexibility can materially reduce distribution infrastructure costs, but they understate the achievable value of flexibility by treating it as a generalized scenario assumption rather than a locational planning resource. The studies rely heavily on historical DR participation, system-average avoided costs, and legacy non-wires alternatives ("NWAs") experience, even though electrification creates a new class of controllable loads and distributed resources that can be targeted to specific feeders, substations, and secondary constraints. The Commission should not interpret the studies as evidence that flexibility is marginal or unreliable. Rather, the studies show that flexibility has measurable value and that the next step is to require IOUs to evaluate locational flexibility procurement as part of the Distribution Planning Process, Grid Needs Assessment, Distribution Deferral Opportunities Report process.

This is the core premise of Clean Coalition's Energy Tetris framework: electrification load, DER deployment, distribution constraints, and infrastructure investments must be planned together rather than in separate silos. Before defaulting to traditional infrastructure upgrades, IOUs should be required to determine whether targeted DER portfolios can shape, shift, or locally serve new load in ways that reduce total system costs and improve resilience.

II. DESCRIPTION OF PARTY

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 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.

III. COMMENTS

The IOU EIS Part 2 reports all show that demand flexibility can materially reduce distribution infrastructure needs. PG&E estimates distribution electrification investments of approximately $23 billion to $31 billion through 2040 depending on scenario, and finds that enhanced orchestrated demand flexibility can reduce distribution infrastructure costs by approximately $1.8 billion compared to its base scenario. SCE estimates approximately $13.1 billion in base distribution costs through 2040, with demand flexibility scenarios reducing costs by approximately $0.32 billion and $1.38 billion. SDG&E estimates approximately $3.202 billion in base distribution costs through 2040, with its demand flexibility scenario reducing costs to approximately $2.505 billion, a reduction of roughly $697 million.

These findings should not be treated as marginal adjustments to traditional utility planning. They demonstrate that the central policy question is no longer whether demand flexibility has distribution value: the studies confirm that it does. The question is whether the Commission will require the IOUs to plan, procure, operationalize, and compensate that value with the same seriousness applied to traditional infrastructure.

Cal Advocates' 2025 DGEM analysis also reinforces this point by estimating distribution upgrade costs through 2040 and evaluating how those costs vary under different levels of building electrification and electric vehicle charging management. Together, DGEM and EIS Part 2 studies have a clear conclusion: electrification will increase distribution system needs, but those needs can be materially shaped by how, when, and where load is added, which is precisely why flexibility must become a core input into distribution planning.

A. The Commission should require "Energy Tetris" planning: matching electrification load, DERs, grid constraints, and local flexibility before defaulting to wires upgrades

Affordability is inherently driven by the amount of infrastructure required to serve peak demand, especially when the biggest component of residential electricity bills is delivery costs. Clean Coalition has described the needed planning reform as Energy Tetris: California must stop treating new load, DER adoption, distribution constraints, and infrastructure investments as separate planning silos.[1] Instead, the Commission should require planning that fits these pieces together in the places and hours where they matter most. Energy Tetris has two foundational components that are directly supported by the EIS Part 2 record.

Part 1 is location-aware electrification planning. Electrification load should not be treated only as an aggregate system forecast. New EV charging, building electrification, industrial load, and fleet load should be mapped to the circuits, substations, and secondary networks where constraints will actually arise. The EIS Part 2 studies begin this work by moving from system-level electrification forecasts toward feeder, circuit, substation, and secondary-system impacts. The Commission should now require this analysis to become actionable in the Distribution Planning Process, Grid Needs Assessment, and Distribution Deferral Opportunity Report.

Part 2 is DER and flexibility integration. Once the location and timing of grid needs are identified, the IOUs should be required to evaluate whether a portfolio of DERs, managed charging, storage, flexible interconnection, dynamic pricing, and DERMS-enabled dispatch can avoid or defer the traditional upgrade. This is the missing step in the IOU studies. Each utility recognizes the value of flexibility, but none fully converts that value into a core planning and procurement framework.

The Commission should not allow the IOUs to treat flexibility as an after-the-fact sensitivity. If the studies show that flexibility can reduce billions of dollars of distribution costs, then flexibility must be incorporated into the base planning case and into the procurement tools used to meet identified grid needs.

B. The IOU studies are useful, but they understate the achievable value of DER flexibility

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

The EIS Part 2 studies are important because they acknowledge the cost-reduction potential of demand flexibility. But they remain overly conservative in at least three ways: they understate the amount of flexible load that can be procured, they understate local deferral value, and they fail to fully test cost-effectiveness using a portfolio of targeted DER solutions.

i. PG&E shows substantial flexibility value, but does not convert that value into a planning requirement

PG&E's study is the most constructive of the three because it directly models enhanced orchestrated demand flexibility and finds approximately $1.8 billion in reduced distribution infrastructure costs through 2040. PG&E's enhanced flexibility case includes EV charge management, vehicle-to-grid, batteries, and building-electrification demand response, and PG&E estimates multi-gigawatt levels of coincident and non-coincident load flexibility by 2040.

However, PG&E still treats enhanced flexibility as a scenario rather than as a required planning resource. This is a critical limitation. A scenario can show that flexibility has value, but it does not ensure that flexibility will be procured, dispatched, or used to defer specific investments. The Commission should require PG&E to translate this modeled value into a locational flexibility planning case, including identified circuits, substations, and secondary-system constraints where flexible resources could compete against traditional infrastructure.

PG&E also notes that it does not fully evaluate the costs of implementing and orchestrating enhanced flexibility. However, that is not a reason to discount flexibility, it is a reason to require the IOUs to test reasonable procurement cost bands for local flexibility. The correct comparison is not "free flexibility" versus "known wires costs." The correct comparison is contracted DER flexibility, with reasonable program and control costs, against the avoidable cost of traditional upgrades.

ii. SCE correctly focuses on local circuit peaks, but still frames flexibility too cautiously

SCE's study is important because it recognizes that distribution constraints are often driven by non-coincident local peaks, not simply system coincident peak demand. That is the correct planning lens. A DER portfolio may have modest system-level value but high local value if it reduces a specific feeder, transformer, or substation constraint at the hour when that asset is overloaded.

SCE estimates that its demand flexibility cases reduce distribution costs by approximately $0.32 billion and $1.38 billion, respectively. But SCE appears to present its higher-flexibility case as more of a theoretical upper bound than an actionable procurement path. That framing is too conservative. Universal participation may not be realistic for all residential customers, but the relevant question for distribution planning is not whether every customer voluntarily enrolls in legacy demand response. The relevant question is how much flexibility can be procured or required from resources that are already controllable: fleet depots, managed EV charging, customer batteries, building controls, VPP aggregations, flexible interconnection agreements, and DERMS-dispatchable portfolios.

The Commission should require a middle planning case between low historical participation and theoretical full participation. That case should reflect achievable participation through tariffs, incentives, interconnection requirements, aggregator contracts, and distribution-level procurement.

iii. SDG&E recognizes major flexibility savings, but relies too heavily on historical NWA and avoided-cost limitations

SDG&E's study is the most conservative. SDG&E estimates that demand flexibility could reduce distribution costs by roughly $697 million through 2040, yet it does not fully evaluate non-wires alternatives as a forward-looking procurement tool. Instead, SDG&E leans heavily on historical demand response experience, system-level avoided-cost logic, and the prior discontinuation of the Distribution Investment Deferral Framework.

That approach risks drawing the wrong lesson from history. The fact that legacy DR or DIDF solicitations may not have produced sufficient deferral resources does not mean modern DER flexibility cannot defer future electrification-driven upgrades. Electrification creates a different resource base: EV chargers that can be scheduled, batteries that can be dispatched, fleets that can respond to managed charging requirements, and behind-the-meter resources that can be coordinated through aggregators or DERMS platforms.

SDG&E also acknowledges that system-level avoided costs may not reflect the value of avoiding specific circuit-level upgrades. That acknowledgment is critical. If the distribution need is local, the value must also be local. A system-average avoided-cost framework will tend to understate DER value precisely where DERs are most useful: constrained circuits, substations, and secondary networks.

C. DERs should be capitalized and value-stacked, not treated as single-purpose customer programs

The deeper problem revealed by the EIS Part 2 studies is that the IOUs still tend to evaluate DERs through narrow program categories. A managed EV charging program is treated as load management. A battery is treated as backup power, customer bill management, or resource adequacy. A solar-plus-storage system is treated as a customer-sited resource or interconnection issue. A VPP is treated as a wholesale or emergency reliability tool. However, DER are most valuable when they are capitalized and value-stacked across multiple grid needs. A single DER portfolio may provide:

- customer bill savings;
- local distribution deferral;
- peak reduction;
- resource adequacy;
- resilience;
- transmission cost avoidance;
- greenhouse gas reductions;
- wholesale market value;
- outage mitigation; and
- electrification enablement.

Current planning does not adequately monetize this full stack. As a result, DERs can appear uneconomic when viewed through one narrow value stream, even though they may be cost-effective when their full portfolio of benefits is considered. This is particularly important for local solar, storage, managed charging, and Community Microgrids, which can serve customer, distribution, resource adequacy, and resilience functions simultaneously.

The Commission should therefore require the IOUs to evaluate DER portfolios not as isolated programs, but as capital resources capable of providing stacked grid services. Where a DER portfolio can reduce or defer a distribution upgrade, serve local load, provide dispatchability, and support resilience, the IOU should be required to compare that portfolio against the traditional infrastructure alternative.

D. The Commission should make flexibility a core planning requirement

The EIS Part 2 studies should lead to a simple conclusion: unmanaged electrification is expensive, and managed electrification is materially cheaper. The Commission should therefore require the IOUs to incorporate flexibility into core planning, not merely study it as a sensitivity.

Clean Coalition recommends that the Commission direct the IOUs to:

1. Create a Locational Flexibility Planning Case in the Distribution Planning Process, Grid Needs Assessment, and Distribution Deferral Opportunity Report.
2. Use local deferral value, not only system-average avoided costs, when evaluating DERs that can address specific circuit, substation, or secondary-system constraints.
3. Model achievable flexibility, not merely historical demand response participation. This should include managed charging, fleet charging controls, customer batteries, VPPs, dynamic pricing, flexible interconnection, and DERMS-dispatchable portfolios.
4. Require DER portfolios to compete against traditional infrastructure where they can meet the same need with sufficient reliability, availability, and locational precision.
5. Value-stack DER benefits across distribution deferral, resource adequacy, resilience, transmission avoidance, customer savings, and emissions reductions.
6. Align electrification planning with DER deployment, so that new load growth is paired with local clean energy, storage, and flexible load management before utilities default to grid expansion.

This is the practical next step for Energy Tetris. California should not plan for electrification by assuming every new load addition must be served through traditional infrastructure. The Commission should require the IOUs to first determine whether electrification load can be shaped, shifted, paired with DERs, or served locally in ways that reduce total system costs.

VI. Proposed conclusion for this opening section

IV. CONCLUSION

The Clean Coalition appreciates the opportunity to submit these comments. EIS Part 2 studies should not be used to justify a larger and more expensive version of the existing distribution planning paradigm. They should be used to change that paradigm. The studies show that demand flexibility can reduce distribution costs, but the IOUs have not yet incorporated that flexibility into core planning in a way that will reliably produce those savings for ratepayers.

The Commission should therefore direct the IOUs to move beyond identifying flexibility as a potential benefit and begin treating DER flexibility as a planned, procured, and compensated grid resource. Doing so is essential to achieving affordable electrification, reducing unnecessary infrastructure costs, and ensuring that California's distribution grid is modernized around the

capabilities of distributed energy resources rather than built around the assumption that DERs remain peripheral to grid planning.

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