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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

COMMENTS OF THE UTILITY CONSUMERS' ACTION NETWORK ON THE ELECTRIFICATION IMPACT STUDY PART 2 DRAFT REPORTS FILED BY SAN DIEGO GAS & ELECTRIC, SOUTHEN CALIFORNIA EDISON, AND PACIFIC GAS & ELECTRIC ON OCTOBER 31, 2025

Saeed Manshadi, Ph.D.
Independent Consultant
manshadi@ieee.org

Jane Krikorian
Staff Attorney
Utility Consumers' Action Network
404 Euclid Ave, Suite 377
San Diego, CA 92114
619-696-6966
jane@ucan.org

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I. INTRODUCTION

As a part of the above-captioned proceeding, the California Public Utilities Commission (CPUC or Commission) required San Diego Gas & Electric Company (SDGE), Southern California Edison Company (SCE), and Pacific Gas & Electric Company (PGE) (collectively "the IOU's") to each file a draft report assessing their respective load flexibility distribution planning processes (DPP) as a part of the ongoing assessments in this proceeding to improve the IOU's Distribution Planning and Execution Processes (DPEP's). These assessments, also referred to as the Electrification Impact Studies (EIS) Part 2, or Draft Reports, were originally due by September 30, 2025.[1] On September 24, 2025, the Commission's Executive Director granted an extension request from the IOU's setting the Draft Reports deadline for October 31, 2025. The letter also set the deadline for party comments to December 15, 2025.[2] The Utility Consumers' Action Network (UCAN)[3] therefore timely and respectfully submits these Comments on the IOU EIS Part 2 Draft Reports. A final report from the IOU's incorporating

[1] D.24-10-030, Ordering Paragraph (OP) 19 at pp. 197-198
[2] 9-24-25 D2410030_Executive Director Letter Granting Extension of Time JC (003).pdf
[3] UCAN is a 501(c)(3) non-profit public benefit corporation dedicated to protecting and representing the interests of residential and small business customers in the San Diego Gas & Electric service territory. Approximately 98% of UCAN's members are residential customers. UCAN has been active in Commission proceedings since 1983 and strives to meet the Commission's goals for rates that are equitable and affordable for all ratepayers.

party comments on how the Draft Report findings should be incorporated into the DPEP's, is due on January 28, 2026.

UCAN appreciates the significant effort undertaken by SDG&E, PG&E, SCE to produce the EIS Part 2 Draft Reports. These studies represent a massive data-gathering exercise. However, based on our technical review of the filings and the data gathered through discovery, UCAN registers a fundamental concern regarding the utility of these documents for future planning.

While UCAN supports the Commission's goal of integrating Demand Flexibility into grid operations, the EIS Part 2 in its current form is a "half-finished bridge"—it effectively shows us the destination of grid deferral but hides the toll we must pay to cross it. By modeling capital deferral without modeling the associated program costs, and by identifying grid needs based on deterministic engineering heuristics rather than probabilistic optimization, the IOUs have produced studies that are mathematically consistent but methodologically disconnected from modern best practices.

A. Utilities Studies Are Disconnected from Modern Best Practices

A core objective of this rulemaking is to modernize the electric grid. Regrettably, while the IOUs performed the necessary *calculation* required by Ordering Paragraph 19, they failed to perform the necessary *science* of modern distribution planning. UCAN's review compared the IOUs' methodologies against the body of research established by the U.S. Department of Energy (DOE), Lawrence Berkeley National Laboratory (LBNL), and Pacific Northwest National Laboratory (PNNL). This comparison reveals a stark divergence:

- **The Utility Approach:** The IOUs relied on deterministic snapshots—scaling a single "worst-case" peak load profile out to 2040 and applying manual or simplified decision trees to solve for thermal capacity.

- **The Scientific Standard:** The DOE's Integrated Distribution System Planning (IDSP) framework and PNNL Report 28138 establish probabilistic, multi-objective planning as the emerging standard.[4] This approach accounts for the uncertainty of adoption and co-optimizes for cost, reliability, and equity, rather than solving for a single thermal constraint.

- **The Resulting Deviation:** Because the IOUs utilized legacy tools for a modern problem, the study results likely represent an "Upper-Bound Wires Ceiling"—the cost of the grid if we refuse to innovate—rather than an optimized roadmap. The results reflect a conservative administrative preference that systematically inflates the need for capital investment.

B. Utilities Cost Discrepancies Illustrate Methodological Weaknesses

The methodological weaknesses of the current studies are best illustrated by the massive, unexplained discrepancies between the three utilities regarding the Secondary System (service transformers and lines):

- **PG&E** projects **$15.9 billion** in secondary costs, driven by expensive new service connections.

- **SCE** projects only **$0.9 billion**, explicitly excluding new service connections due to a lack of methodology.

- **SDG&E** falls in the middle but relies on manual solutioning and an overly conservative "8-hour" thermal loading assumption.

This variance is not driven by the physics of the grid; it is driven by inconsistent modeling choices. The Commission cannot set statewide policy or authorize spending based on data where one utility forecasts a $15 billion need and its neighbor forecasts near-zero for the exact same asset class.

[4] J. S. Homer et al., Electric Distribution System Planning with DERs: High-Level Assessment of Tools and Methods, Pacific Northwest National Laboratory (PNNL-28138, 2020).

C. Utilities Methodological Suppression of Flexibility and its Potential Value

The IOUs have produced a study that demonstrates the potential value of flexibility, yet methodologically suppresses its viability. This suppression occurs through three primary vectors:

- **The "Missing Money":** By excluding the administration and incentive costs required to achieve demand flexibility, the study prevents a true cost-benefit analysis. We are left with a false comparison between a "fully loaded" infrastructure cost and a "capital-only" flexibility savings.
- **Improperly Justified Engineering Standards:** As detailed below, SDG&E's use of an *8-hour continuous loading standard* for 4-hour residential EV charging creates a phantom constraint that would not exist under a dynamic thermal rating framework.
- **Ignoring Commercial Technology:** Perhaps most critically, PG&E and SDG&E admitted to ignoring commercially available non-wires technologies, such *as smart panels and circuit splitters*. DOE research confirms these technologies can mitigate secondary system upgrades at a fraction of the cost of civil work.[5]

D. SDGE's Failure to Fulfill the Modernization Mandate

SDG&E's report explicitly states that the Equity and Demand Flexibility scenarios are "hypothetical" and "carry little weight" in anticipating future infrastructure needs. UCAN argues that this admission renders the study non-compliant with the spirit of the Commission's order. If the utility views these modernization scenarios as mere academic exercises that carry "little weight" compared to their traditional Base Case, it suggests an intention to proceed with "Business as Usual" regardless of the study's findings.

E. Validation Through Discovery and UCAN Recommendations

To substantiate these concerns, UCAN served targeted Data Requests on SDG&E, SCE, and PG&E. The responses, attached hereto, confirm that the current grid needs assessments are artificially inflated by conservative assumptions. Therefore, to protect ratepayers from the risk of

[5] U.S. DOE & LBNL, Packages of DER Technologies for Demonstrating Demand Flexibility at Community Scale (2025).

premature and excessive capital spending based on these illustrative estimates, UCAN respectfully submits the following recommendations:

1. **Supplemental Sensitivity Analysis:** UCAN recommends the Commission direct the IOUs to provide specific **"Likely Achievable"** sensitivities (based on LBNL Phase 4 data) and **"Total Resource Cost"** estimates (including program costs) before the Final Report is accepted.

2. **Incomplete Record:** The EIS Part 2 cannot be considered finalized until the "Missing Money" (program costs) is accounted for.

3. **Non-Precedential Status:** The Commission must explicitly rule that the cost estimates in these reports are **illustrative only**. They must not serve as the evidentiary basis or a rebuttable presumption of reasonableness for the 2026 Distribution Planning Process (DPP) or future General Rate Cases (GRC).

II. DISCUSSION

A. DEMAND FLEXIBILITY SCENARIOS: INCOMPLETE EQUATIONS AND MODELING SIMPLIFICATIONS

The EIS Part 2 was intended to illuminate the potential for demand-side resources to defer grid infrastructure. However, a rigorous review of the modeling choices reveals that the scenarios presented are structurally incomplete. By presenting a Flexibility Scenario that includes capital benefits but excludes operating costs, and by relying on "shape" modifications that ignore the conservation of energy, the study provides a distorted picture that discourages the adoption of non-wires alternatives.

The IOUs have effectively calculated the *gross revenue* of flexibility without calculating the *operating expense*, rendering the final "Net Value" undeterminable.

1. The "Missing Money" Problem: Excluding Program Costs Prevents Cost-Effectiveness Analysis

A fundamental principle of utility regulation is determining the "Least Cost" path to reliability. The EIS Part 2 fails this basic test by comparing a fully-costed "Base Case" (infrastructure) against a partially-costed "Flexibility Case" (capital savings only).

- **The Utility Approach:** In response to **UCAN Data Request 3b**, SDG&E candidly admitted: *"SDG&E has not analyzed the cost-effectiveness of this scenario"* and confirmed that program costs were excluded. The IOUs modeled the capital deferral benefits of flexibility (e.g., 0) to the program administration, marketing, technology platforms (DERMS), and customer incentives required to procure that flexibility.

- **The Scientific/Regulatory Standard :** Established regulatory practice, codified in the CPUC's Standard Practice Manual and D.90-07-046, requires a Total Resource Cost (TRC) analysis for demand-side programs.[6] Furthermore, the LBNL Phase 4 Demand Response Potential Study—which the utilities cite as their source—explicitly includes these cost layers in its economic potential modeling to ensure viability.

- **The Resulting Deviation:** This omission creates an "Apples-to-Oranges" comparison. We cannot determine if Demand Side Management (DSM) saves ratepayers money if the "price" of procuring that DSM is hidden. The study quantifies the *technical potential* of flexibility but fails to provide the *business case* for it, biasing the planning outcome toward the "known quantity" of traditional infrastructure.

2. The "Straw Man" Scenario: Selecting High Enrollment to Pre-Load Risk

Rather than modeling a realistic, achievable growth path for demand response, the IOUs selected "High" enrollment assumptions for the Demand Flexibility scenario, creating a scenario that appears operationally risky and impractical.

- **The Utility Approach:** The IOUs modeled aggressive "High" participation rates (often approaching 100% in alternative scenarios) while simultaneously ignoring the "Likely Achievable" data provided by LBNL. In response to **UCAN Data Request 3a**, SDG&E admitted they do not have the data readily available to compare economic versus achievable potential.

- **The Scientific Standard :** LBNL Phase 4 distinguishes between "Economic Potential" (what is cost-effective) and "Likely Achievable Potential" (what can realistically be adopted based on historical barriers and adoption curves). Best practice in resource planning requires modeling the "Likely Achievable" path to establish a reliable baseline for deferral.[7]

- **The Resulting Deviation:** By utilizing only the aggressive "High" scenario without the corresponding "Achievable" baseline, the study constructs a **"Straw Man."** This allows the utilities to present Demand Flexibility as a high-risk, theoretical exercise that relies on near-perfect customer behavior, rather than a reliable planning resource. This framing

[6] California Public Utilities Commission, Decision 90-07-046 (July 1990).

[7] B. F. Gerke et al., The California Demand Response Potential Study, Phase 4: Report on Shed and Shift Resources Through 2050, Lawrence Berkeley National Laboratory (2024).

subtly justifies a reversion to "Business as Usual" wires solutions by characterizing flexibility as too speculative for grid reliance.

3. **The "Shift vs. Shed" Technical Flaw: Ignoring Thermal Rebound**

Perhaps the most technically concerning flaw is the simplification of load "Shifting" as load "Shedding."

- **The Utility Approach:** In the Demand Flexibility scenario, SDG&E modeled the movement of energy consumption away from peak hours by effectively removing it from the model (Shed) during the peak window, without explicitly modeling the **"Rebound"** (adding it back) in the off-peak hours.

- **The Scientific Standard:** The Lawrence Berkeley National Laboratory's Phase 4 Demand Response Potential Study (2024) establishes a critical distinction between Shift and Shed as demand response resources. In the LBNL framework, Shed represents direct load reduction during peak periods where energy is removed from the grid entirely, whereas Shift represents the movement of energy consumption from peak to off-peak periods, with total energy remaining constant.[8] Energy is conserved; if an EV is not charged at 6:00 PM, that load *must* reappear at another time. Modeling the **"Rebound Peak"**, which is often a sharp synchronization of devices turning on at midnight, is critical for assessing secondary transformer thermal stress.[9]

- **The Resulting Deviation:** By failing to model the thermal rebound, the study violates the law of conservation of energy within the dispatch window.

    - **Understating Risk:** It masks potential *new* thermal overloads that occur during the rebound window (e.g., midnight timer peaks), which might require different mitigations (like randomized delay timers).

    - **Undervaluing Orchestration:** It fails to capture the value of advanced orchestration tools that smooth these rebounds.

    - **Impact:** This simplification renders the flexibility scenario unreliable for true distribution power flow analysis, as it solves a voltage problem at 6:00 PM while potentially hiding a thermal problem at 12:00 AM.

[8] Id. The LBNL Phase 4 study notes: "Shed and shift DR are considered 'event-based' and would only be called upon in the hours of highest grid need." Shift is responsive to continuous price signals and requires different program design than Shed.
[9] Zhu, Xiangqi and Barry Mather (2020). "Data-Driven Load Diversity and Variability Modeling for Quasi-Static Time-Series Simulation on Distribution Feeders." NREL/PO-6A20-73146.

B. ENGINEERING CONSERVATISM: HOW LEGACY STANDARDS ARTIFICIALLY INFLATE GRID NEEDS

The validity of any infrastructure forecast rests entirely on the engineering standards used to define a "need." If the standards are excessively conservative, applying industrial safety margins to residential behaviors, the resulting cost estimates will be mathematically correct but operationally unjustified. Our analysis of the discovery record reveals that SDG&E utilized engineering heuristics that diverge from modern scientific consensus on asset utilization. By decoupling the thermal physics of transformers from the actual duration of EV loads, and by relying on manual project selection rather than algorithmic optimization, the utility has produced a forecast that systematically provides improperly justified upgrades to the distribution grid.

1. The "8-Hour" Thermal Loading Rule: A Disconnect from Residential Reality

The most critical technical finding regarding secondary system costs concerns the specific criteria SDG&E uses to flag a transformer for replacement. Transformers are oil-filled devices with significant "thermal inertia", they do not overheat instantly when load exceeds their nameplate rating; it takes time for the temperature to rise to damaging levels.

- **The Utility Approach:** In response to **UCAN Data Request 1a**, SDG&E admitted: *"SDG&E elected to assume an 8-hour continuous loading... The 4-hour and 8-hour allowable loading percentages are marked... at 1.36 and 1.21, respectively."* Essentially, SDG&E determined that a transformer fails if it exceeds **121%** of its rating, based on the assumption that the peak load persists for 8 continuous hours.

- **The Scientific Standard:** IEEE Standard C57.91-2011 (Guide for Loading Mineral-Oil-Immersed Transformers) provides specific guidelines for "Planned Overloading." Because residential Electric Vehicle (EV) charging events (Level 2) typically peak for 3 to 4 hours, not 8 hours, the standard permits a significantly higher overload factor due to thermal lag. Under the very table cited by SDG&E, a transformer can safely handle **136%** of its rated load for a 4-hour duration without exceeding thermal limits.[10]

[10] IEEE Standard C57.91-2011: Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators, Table 7.

- **The Resulting Deviation:** By applying an "industrial" continuous-duty standard (8-hour) to a "residential" intermittent load (EVs), SDG&E artificially lowered the failure threshold from 136% to 121%.
    - **Impact:** Any transformer projected to load between 121% and 136% was flagged for replacement in the study, despite being thermally capable of serving the load. UCAN submits that this conservatism likely invalidates a significant portion of the projected replacements in the Equity and Demand Flexibility scenarios.

2. **The "Scale Factor" Misconception: How the Snapshot Method Overestimates Infrastructure Needs**

Modern grid planning requires understanding *when* loads occur, not just *how big* they are. This is particularly true in a high-DER future, where solar generation, AC usage, and EV charging interact in complex ways throughout the day and year.

- **The Utility Approach:** SDG&E's secondary system analysis utilized a "snapshot" method, taking peak data from five days in September 2024 and applying a single **"Scale Factor"** to predict 2040 loads. This approach treats load growth as a linear scalar—if peak in September is X MW, then peak in 2040 will be X × (1 + growth rate) MW.

- **The Scientific Standard:** The NREL has established Quasi-Static Time Series (QSTS) analysis as the standard for modern distribution planning. NREL's flagship tool, Distribution Integration Solution Cost Options (DISCO),[11] is specifically designed to perform dynamic hosting capacity analysis using 8,760-hour yearly load simulations.

  QSTS analysis recognizes that the highest solar export does not occur at the same time as the highest EV demand, and that winter peaks (heating) stress equipment differently than summer peaks (cooling) due to ambient air temperature variations. A snapshot method that assumes "worst case on top of worst case", where every load reaches its seasonal peak simultaneously, will systematically overestimate infrastructure needs.

  This principle was validated in NREL's landmark Los Angeles 100% Renewable Energy Study (LA100), which analyzed distribution system impacts across more than 1,500 feeders using QSTS analysis with DISCO. The LA100 study found that snapshot-based hosting capacity estimates significantly overstated grid constraints compared to dynamic, time-series analysis.

- **The Resulting Deviation :** By using a single scalar factor instead of 8,760-hour time-series analysis, SDG&E's study:

[11] Abraham, Sherin Ann and Shibani Ghosh, Distribution Integration Solution Cost Options (DISCO), NREL/TP-6A40-89565 (April 2024). DISCO was used to conduct distribution analysis in the Los Angeles 100% Renewable Energy Study (LA100), which analyzed 1,500+ distribution feeders using quasi-static time-series analysis. See Ramasamy, Venkat, et al., The Los Angeles 100% Renewable Energy Study (LA100): Chapter 7 - Distribution and Grid Modernization, NREL (2021), https://research-hub.nrel.gov/en/publications/the-los-angeles-100-renewable-energy-study-la100-chapter-7-distri/

- **Masks Load Diversity:** The scalar approach ignores the fact that residential AC demand peaks at 7-8 PM in summer, while EV charging peaks at 10-11 PM. By overlapping these peaks arbitrarily, the analysis overstates the coincident load.
- **Ignores Seasonal Variation:** Winter and summer peaks have different profiles due to heating vs. cooling. A scalar factor applied uniformly across all seasons cannot capture this.
- **Overestimates Transformer Needs:** Secondary transformers serving residential circuits will see different maximum loads depending on the time of year. A September snapshot does not represent typical winter or spring conditions.
- **Prevents NWA Evaluation:** Time-series analysis reveals specific hours when constraints occur, enabling targeted flexibility solutions (e.g., "shift 10% of midnight EV charging to 2-4 AM"). Snapshot analysis cannot identify these windows.

- **Remedy:** SDG&E should conduct a QSTS analysis using NREL's DISCO tool (or equivalent) on a representative sample of 10-20 secondary circuits to quantify the difference between snapshot and time-series results. Such an analysis would likely demonstrate that secondary infrastructure needs are overstated by 10-20% through the use of conservative scalar factors.

3. Manual Solutioning Bias: A Spending Plan, Not a Planning Study

The complexity of a 15-year grid transition involves millions of variables. Determining the most cost-effective solution for a constraint requires comparing wires, batteries, transfers, and load management simultaneously to find the efficient frontier.

- **The Utility Approach:** In response to **UCAN Data Request 2a/b**, SDG&E admitted to using **"no automated scripts"** for solutioning, relying instead on "general principles" applied by planners. Furthermore, they confirmed that *"Non-Wires Alternatives (NWA) were not considered"* because no detailed scoping was performed.

- **The Scientific Standard:** The DOE's **Integrated Distribution System Planning (IDSP)** framework explicitly calls for *co-optimization*.[12] Modern planning utilizes algorithmic engines that sort through thousands of permutations to objectively select the *least-cost* solution, verifying whether a $2 million battery is cheaper than a $10 million circuit upgrade.

- **The Resulting Deviation:** Manual planning defaults to human heuristic bias: "When in doubt, build a wire." A human engineer cannot manually optimize a 15-year multi-

[12] U.S. Department of Energy, Office of Electricity, Integrated Distribution System Planning (IDSP) (2020).

variable equation across thousands of circuits.

  - **Impact:** Because SDG&E lacked an optimization engine, this document effectively represents a **Spending Plan** (a list of assets the utility wishes to purchase) rather than a **Planning Study** (an objective analysis of what the grid requires). Without automated NWA screening, the cost estimates provided must be viewed as a theoretical ceiling, not a validated budget.

C. THE OPAQUE METHODOLOGY OF SECONDARY SYSTEMS: A FAILURE TO MODEL NON-WIRES ALTERNATIVES

The single largest cost driver in the distribution grid transition often lies in the "last mile"—the secondary system of service transformers and service drops. Addressing these constraints effectively requires a surgical application of technology. However, our review of the data requests indicates that the IOUs have opted for a blunt-force approach, systematically ignoring commercially available technologies that could avoid billions in spending.

1. The "Smart Panel" Blind Spot: Forcing a Copper-Only Solution that Artificially Inflates Secondary System Costs

The most troubling admission in the discovery record is the utility's failure to acknowledge technologies that manage load "behind the meter" to protect the grid "in front of the meter."

- **The Utility Approach:** In response to **UCAN Data Request 4b**, SDG&E stated: *"SDG&E responds that it is not aware of any cost-benefit analyses comparing the cost of utility service upgrades to the cost of customer-side smart panels."* Consequently, the study modeled **zero adoption** of circuit splitters, smart panels, or meter collar adapters in the Base or Equity scenarios.

- **The Scientific/Industry Standard:** It is technically incongruous for a major utility in 2025 to claim a lack of data regarding this technology. Smart panels and current-limiting devices are commercially mature technologies actively piloted by California utilities. Pacific Gas and Electric's Seasonal Aggregation of Versatile Energy (SAVE) program (launched March 2025) explicitly includes up to 400 customers with smart electric panels manufactured by SPAN, coordinating load management at the distribution circuit level (also called 'precision grid surgery' or 'neighborhood-level constraints'). The SAVE pilot demonstrates that smart panel technology can reduce local grid constraints and defer infrastructure upgrades.[13] It is recognized by the **DOE & LBNL** as core components of

[13] PG&E Press Release, "PG&E Launches Seasonal Aggregation of Versatile Energy (SAVE) Virtual Power Plant Program" (March 24, 2025). The SAVE program includes "up to 1,500 electric residential customers with battery

demand flexibility packages.[14] These devices act as a "virtual capacity upgrade," allowing a customer to add an EV charger without exceeding their existing service wire limits.

- **The Resulting Deviation:** By treating the customer service connection as a passive copper wire rather than an intelligent node, the IOUs have forced a **"Copper-Only"** solution. They assume every increase in demand requires a physical upgrade of the transformer and wire. This methodological omission artificially inflates secondary system costs by ignoring a solution that costs a fraction of civil trenching and hardware replacement.

2. The "Cumulative Data" Limitation: Prohibits Targeted Cost-Saving Measures

Effective Demand Side Management (DSM) requires knowing exactly *what* is causing the peak. You cannot fix a problem you cannot isolate.

- **The Utility Approach:** In response to **UCAN Data Request 4b**, SDG&E stated they cannot disaggregate EV-driven upgrades from general load growth upgrades because *"Load growth and EV contribution were accounted for in a cumulative way... and cannot be disaggregated."*

- **The Scientific Standard:** Modern distribution planning relies on **End-Use Disaggregation**. Methodologies established by **NREL** and **LBNL** utilize AMI data to separate flexible loads (EVs) from rigid loads (lights/appliances). This distinction is vital because flexible loads can be managed via software, while rigid loads must be served by iron.

- **The Resulting Deviation:** Because SDG&E treats all load as a monolithic "cumulative" block, they deny themselves the ability to target solutions. If the utility cannot distinguish a transformer overload driven by an EV (fixable via managed charging) from one driven by AC load (requiring an upgrade), they default to upgrading both. This data opacity effectively prohibits targeted cost-saving measures in the model.

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energy storage systems and up to 400 customers with smart electric panels" to be "dispatched for up to 100 hours from June through October 2025, providing localized support by supplying battery power and load flexibility to selected neighborhoods during local peak demand periods."

[14] U.S. Department of Energy and Lawrence Berkeley National Laboratory, Packages of Distributed Energy Technologies Demonstrating Demand Flexibility at Community Scale (Technical Report, 2025).

3. Treating Flexibility as a Modifier Rather than Competitor Undervalues DERs

Finally, the study fails to answer the central question of this proceeding: "Can Distributed Energy Resources (DERs) replace wires?" The methodology used by the IOUs suggests they never actually asked the question on a project-by-project basis.

- **The Utility Approach:** There is no evidence in the record that SDG&E screened specific primary upgrades for Non-Wires Alternative (NWA) suitability. Instead, they simply lowered the global load forecast slightly in the Flexibility Scenario and checked if the wire still overloaded.
- **The Scientific Standard:** Best practices defined by the **EPRI NWA Integration Guide** and demonstrated by Con Edison's **Brooklyn-Queens Demand Management (BQDM)** program require a competitive screening process. In these frameworks, specific capital projects are stress-tested against a portfolio of DERs. EPRI's guide explicitly covers "Systems Needs Assessment and NWA Screening" and establishes that utilities should conduct "competitive screening" of DER-based alternatives before traditional infrastructure upgrades. The guide addresses "project-by-project" evaluation of whether DERs can "defer, mitigate, or eliminate traditional 'wire' solutions. The question is not "does the load drop?" but "can a 10 MW battery portfolio defer this specific $20 million substation upgrade for 5 years?"[15]
- **The Resulting Deviation:** By using flexibility only as a passive load modifier rather than an active project competitor, the study structurally undervalues DERs. It captures the *energy* value of flexibility but misses the *capacity deferral* value of NWAs. The result is a plan that builds infrastructure for peaks that could have been cost-effectively shaved.

D. THE EQUITY SCENARIO: TREATING JUSTICE AS A BURDEN RATHER THAN AN OPTIMIZATION CHALLENGE

The Commission directed the IOUs to study an Equity Scenario to ensure that Disadvantaged Communities (DACs) are not left behind in the energy transition. However, UCAN's analysis of the methodology reveals that the utilities treated this scenario as a blunt-force mathematical exercise rather than a sophisticated planning optimization. By simply stacking "phantom load" onto DAC circuits to meet a quota, without applying concomitant demand-side management or weatherization, the IOUs have constructed a narrative where equity

[15] Electric Power Research Institute, Integrating Non-Wires Alternatives into Utility Planning: 2023 EPRI Research Guide (August 2023). EPRI Technical Report 3002027412.

is synonymous with high costs ($300 million for SDG&E). This approach is scientifically unsound and policy-deficient because it models equity as a stressor rather than a resource.

1. The "Spreadsheet Equity" Approach: A Gap-Filling Exercise

The primary flaw in the Equity Scenario is that it allocates load based on a spreadsheet ratio, not on a realistic adoption forecast or an optimized resource plan.

- **The Utility Approach:** In response to **UCAN Data Request 5b**, SDG&E confirmed that the specific infrastructure upgrades identified in this scenario were triggered *solely* by an incremental ~1,000 MW adder designed to "close the gap" to a theoretical equity ratio. When asked for the specific engineering details of these upgrades, SDG&E refused, citing that it was *"unduly burdensome"* to disaggregate the data.

- **The Scientific/Industry Standard:** Modern distribution planning does not treat load growth in isolation. Best practices in **Targeted Electrification** recognize that low-income customers live in housing stock that often requires significant weatherization. Therefore, a scientific model would pair the addition of heat pump load in a DAC with the addition of insulation and smart controls (the "Efficiency First" principle).

- **The Resulting Deviation:** By modeling Equity purely as a **"Load Adder"** rather than a **"Resource Bundle,"** the IOUs created a worst-case scenario. They stacked unmitigated load onto potentially older infrastructure, naturally resulting in a cost premium. This methodology frames equity as a financial burden to the ratepayer base, rather than modeling the *least-cost way* to serve DACs.

2. Misunderstanding Equity: Load Allocation vs. Service Quality

The study assumes that "Equity" is achieved simply by ensuring DACs use as much electricity as wealthy neighborhoods. This definition ignores the functional definition of energy justice established by federal research bodies.

- **The Utility Approach:** The IOUs defined Equity narrowly as a **"Load Allocation Exercise,"** measuring success by whether the percentage of DER MWs in DACs matched the system average.

- **The Scientific Standard:** The *U.S. Department of Energy's Justice40 Initiative* and *Grid Modernization Frameworks* define equity in terms of *benefits*, not just *consumption*.[16] Key metrics include local resilience, reduction of outage frequency (SAIDI/SAIFI), and

[16] U.S. Department of Energy, General Guidance for Justice40 Implementation (2024).

reduction of energy burden (bill savings).

- **The Resulting Deviation:** The study fails to analyze whether DACs suffer from worse baseline reliability or if they would benefit disproportionately from local resilience solutions (like microgrids) rather than wire upgrades.
  - **The Blind Spot:** By focusing solely on wire capacity to serve load, the utility missed the opportunity to analyze whether Non-Wires Alternatives could rectify historical under-investment in reliability for these communities. The study measures "how much copper is needed to serve the load," not "how to improve the quality of life in the DAC."

3. Recommendation: The "Mitigated Equity" Sensitivity

The current Equity Scenario results in a perverse conclusion: that doing the right thing (serving DACs) is prohibitively expensive. This conclusion is an artifact of the modeling choice, not a fact of the grid.

UCAN Recommendation: The Commission should reject the current Equity Scenario results as a "Bookend Analysis" and require a **"Mitigated Equity"** ***Sensitivity***. In this model:

1. **Targeted DSM:** Every MW of new electrification load allocated to a DAC is paired with aggressive, targeted Demand Side Management (DSM) and weatherization assumptions.
2. **Local Generation:** Technical potential for local solar and storage should be prioritized in DACs to reduce the "energy burden" (bills) of the residents.

Only by modeling how equity can be achieved *efficiently* can the Commission determine the true cost of a just transition. The current study measures the cost of negligence, not the cost of equity.

E. COST ESTIMATION FLAWS: SYSTEMATIC BIAS AGAINST NON-WIRES ALTERNATIVES

An Electrification Impact Study is only as valuable as the accuracy of its price tags. For the Commission to determine the "Least Cost" path to reliability, the estimated cost of traditional infrastructure must be comprehensive and rigorous. However, our discovery process confirms that the IOUs have presented a cost estimate that acts as a "thumb on the scale," weighing heavily in favor of building new substations and wires while structurally disadvantaged modern alternatives. By excluding major capital line items (like land) and relying on manual engineering habits rather than algorithmic optimization, the study fails to provide a valid economic comparison.

1. The "Land-Less" Substation: Artificially Discounts Substation Costs

Building new distribution capacity in California, particularly in the dense urban environments where EV load is concentrated, is a real estate challenge as much as an electrical one. Yet, the study explicitly ignores the cost of land, rendering the primary system estimates materially incomplete.

- **The Utility Approach:** In response to **UCAN Data Request 6c**, SDG&E stated simply: *"The EIS Part 2 did not include any costs associated with land acquisition."* Despite forecasting dozens of new substations and bank expansions, infrastructure that requires significant physical footprints, the cost model effectively assumes the land required to host this infrastructure is free.

- **The Scientific/Industry Standard:** Standard cost engineering practices (such as *AACE International* Class 4/5 estimates[17]) require the inclusion of land acquisition, particularly in urban zones where real estate costs can rival equipment costs. Furthermore, *Non-Wires Alternatives (NWAs)*, such as demand response or customer-sited storage, typically require **zero** utility land acquisition.

- **The Resulting Deviation:** By excluding land costs, the utility has artificially subsidized the "Wires" solution. A new substation that appears as a $20 million investment in the model might actually cost $40 million once real estate acquisition and permitting are included. Even SCE's own substation project filings with the CPUC explicitly model 'real estate' as a material cost line item, recognizing that 'property acquisition and/or condemnation costs' are among the major risks to project completion and cost overruns[18]. SDG&E's complete omission of land costs is therefore inconsistent with prevailing utility practice, as demonstrated by the practices of its peer utilities.

    - **The Bias:** This renders the economic comparison to NWAs invalid. A battery storage portfolio (which requires little to no land) is being forced to compete

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[17] AACE International, Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries (February 2005). AACE Recommended Practice 18R-97.
[18] Southern California Edison Application for Riverside Transmission Reliability Project (RTRP), filed with CPUC, November 2013. SCE estimated direct costs of $234.5 million, including explicit line items for 'real estate' acquisition.

against a "discounted" substation price. If the true cost of land were included, the NWA would likely be the clear economic winner.

- **UCAN's Position:** The Commission cannot accept a planning budget based on the fiction of free land.

2. **Manual Solutioning Bias: The "Worst-Case Ceiling" that Fails to Represent an Optimized and Efficient Budget**

Perhaps the most damaging admission regarding the validity of the investment plan is the revelation that it was generated by hand, without the aid of modern optimization software.

- **The Utility Approach:** In response to **UCAN Data Request 2a/b**, SDG&E admitted that *"no automated scripts were used"* for solutioning and confirmed that *"Non-Wires Alternatives (NWA) were not considered"* because no detailed scoping was performed. The utility relied on "general principles" to manually assign wire upgrades to projected overloads.

- **The Scientific Standard:** The *U.S. DOE's Integrated Distribution System Planning (IDSP)*[19] framework and modern utility best practices rely on *Algorithmic Optimization*. A human engineer cannot mentally optimize 15 years of hourly load flows across thousands of feeders to find the lowest-cost solution. Optimization software is required to test thousands of permutations, comparing the Net Present Value (NPV) of a wire upgrade vs. a battery vs. a load transfer, to find the efficient frontier.

- **The Resulting Deviation:** Manual planning inherently defaults to heuristic bias: "When in doubt, build a wire." Without an optimization engine to rigorously challenge every constraint, the resulting project list is not a "Plan", it is a **"Spending Wish List."** SDG&E's approach violates federal IDSP standards in two ways:

    1. *Lack of Documented Methodology:* The utility cannot articulate what "general principles" were applied or how they were consistently implemented across 1,000+ feeders and 10,000+ secondary circuits. This absence of methodology itself violates best practice.

    2. *Failure to Screen NWAs:* By excluding NWAs from detailed scoping, SDG&E deviates from federal guidance requiring "solution identification including non-wires alternatives." The utility's claim that NWA screening was not performed "due to lack of detailed scoping" is circular reasoning: the lack of scoping was a choice, not an unavoidable constraint.

    - **Impact:** Because the IOUs admitted they did not screen for NWAs, the cost estimates in EIS Part 2 represent a **"Worst Case Ceiling"**, the maximum amount

[19] U.S. Department of Energy, Integrated Distribution System Planning (IDSP) Framework (2024).

one could possibly spend if they ignored all modern technology. It does not represent an optimized, efficient budget.

F. PROCEDURAL REMEDIES AND PATH FORWARD: TURNING A "SPENDING WISH LIST" INTO A RIGOROUS PLAN

The ultimate purpose of the EIS is to provide the Commission and stakeholders with a reliable roadmap for the grid of the future. However, a roadmap based on unverified assumptions, excluded costs, and manual heuristics is a map to nowhere. The evidentiary record establishes that the IOUs have produced a study that systematically defaults to high-cost infrastructure while treating cost-saving alternatives as "out of scope." To correct these deficiencies and ensure the 2026 Distribution Planning Process (DPP) serves the public interest, UCAN respectfully submits the following procedural recommendations.

1. Motion to Compel Data: Defining the Scope of "Impact"

In discovery, SDG&E refused to provide data regarding the cost-saving potential of smart panels, objecting that such analysis is *"beyond the scope of the EIS Part 2."* This objection is logically unsound and scientifically invalid. The scope of this proceeding is to determine the *impact* of electrification. Technology that *mitigates* that impact is, by definition, central to the study.

- **The Utility Approach:** The IOUs treated the "Scope" as a narrow exercise in counting wires, explicitly refusing to model customer-side technologies (Smart Panels) that would negate the need for those wires (SDG&E Response to Request 4b).
- **The Scientific/Regulatory Standard :** Modern load forecasting standards (such as those employed by the **CEC's IEPR**[20] and **NREL's Electrification Futures Study**[21]) recognize that "Grid Impact" is a **Net Calculation**: *Gross Load minus Technology Efficiency equals Net Impact*. Ignoring the technology variable renders the equation incomplete. The NREL Electrification Futures Study, the federal standard for analyzing electrification impacts, explicitly models 'hourly load profiles and hourly flexible load

[20] California Energy Commission, 2023 Integrated Energy Policy Report (IEPR). The IEPR forecasting process disaggregates load by end-use technology and accounts for behind-the-meter generation and efficiency adoption.
[21] NREL, Electrification Futures Study: Methodological Approaches for Assessing Long-Term Power System Impacts of End-Use Electrification (2020). NREL/TP-6A40-75784.

profiles' for behind-the-meter technologies, including smart controls and efficiency measures. This accounts for both the gross load increase (from electrification) and the net impact (after accounting for efficiency and demand flexibility). SDG&E's failure to model smart panel adoption is inconsistent with this federal standard.

- **The Resulting Deviation:** By excluding mitigation technologies, the IOUs are calculating **Gross Impact**, not **Net Impact**. This methodology mathematically guarantees an inflated cost estimate.

- **Remedy:** UCAN requests the ALJ direct the IOUs to provide the **"Smart Panel Cost Offset"** estimate and the **"Likely Achievable"** enrollment sensitivity. The Commission cannot accept a cost estimate that assumes 0% technology innovation over the next 15 years.

2. Mandating "Apples-to-Apples" Economic Analysis

The Demand Flexibility scenario currently exists in an economic vacuum. It shows the capital saved but hides the price paid to save it.

- **The Utility Approach:** The IOUs presented a cost comparison that pits a "Fully Loaded" Base Case (Capital + Installation + Overheads) against a "Capital-Only" Flexibility Case (excluding Program Admin, Incentives, and Marketing).

- **The Scientific/Regulatory Standard:** Standard utility economics, codified in the **CPUC's Standard Practice Manual**[22], requires a **Total Resource Cost (TRC)** analysis. To determine the least-cost path, one must compare the **Total Cost of Ownership** of the wires against the **Total Program Cost** of the flexibility.

- **The Resulting Deviation:** This creates an "Apples-to-Oranges" comparison that prevents the Commission from assessing value. We know flexibility reduces capital spend, but we do not know if it reduces the *ratepayer revenue requirement*.

- **Remedy:** Future iterations and the Final Report must include a line-item estimate for program administration and incentive costs in the Demand Flexibility scenario. Even a high-level proxy (e.g., $/kW/year based on current pilots) is scientifically superior to assuming the cost is zero or unknown.

[22] California Public Utilities Commission, California Standard Practice Manual: Economic Analysis of Demand-Side Management Programs (Revised March 2020).

3. Directive for the 2026 DPP: Correct the "Default to Wires" Bias by Utilizing Modern Optimization Software Rather than Manual Solutioning

The most alarming finding from the workshops was the admission that solutioning was performed manually, without optimization software. This "manual bias" must be structurally corrected before the next planning cycle.

- **The Utility Approach:** SDG&E and PG&E admitted their planning logic defaults to traditional upgrades once a thermal limit is hit. SDG&E specifically noted that *"Non-Wires Alternatives were not considered"* because they did not perform detailed scoping.
- **The Scientific/Regulatory Standard:** The **California Energy Loading Order**[23] and the DOE **IDSP Framework**[24] mandate a hierarchy of solutions: Energy Efficiency → Demand Response → Renewables → T&D Upgrades. A valid planning process must **exhaust** the first three categories before resorting to the fourth.
- **The Resulting Deviation:** The current methodology turns the Loading Order upside down. It treats wires as the "Default" and flexibility as a "Sensitivity." This guarantees an inefficient allocation of capital.
- **Remedy:** The Commission should issue a specific directive for the 2026 DPP: The utilities must utilize a solutioning logic or software script that **screens for and exhausts NWAs** *before* triggering any capital upgrade. Any capital project proposed in the 2026 DPP that has not been screened against an NWA alternative should be deemed *prima facie* imprudent.

The flaws in EIS Part 2 are not merely academic; they are structural barriers to a cost-effective energy transition. By compelling the missing data, requiring true economic comparisons, and enforcing an "NWA First" logic for the 2026 DPP, the Commission can transform this study from a justification for spending into a plan for saving.

[23] California Public Resources Code §§ 25001-25999 (Warren-Alquist Act), establishing California's Energy Loading Order. Additionally, CPUC Decision D.12-05-015 (May 2012) operationalizes the Loading Order for utility planning.
[24] U.S. Department of Energy, Integrated Distribution System Planning (IDSP) Framework (2024) and NREL, Integrated Distribution Planning - NREL (2025)

G. SPECIFIC CRITIQUE OF PG&E'S DRAFT REPORT: THE COST OF OBSOLETE ASSUMPTIONS THAT IGNORE MODERN OPTIMZATION TECHNIQUES

PG&E's response to the data request is yet to arrive at UCAN, meanwhile UCAN would like to present specific points regarding the EIS report submitted by PG&E. The draft report presents a staggering price tag of up to $31.6 billion, with a specific focus on a massive expansion of the secondary distribution system. However, a forensic review of PG&E's methodology reveals that these costs are largely the result of "Black Box" modeling decisions that ignore modern optimization techniques. By defaulting to "copper-heavy" solutions while ignoring "silicon-based" alternatives (software and sensors), PG&E has produced a forecast that is disconnected from the scientific consensus on modern grid planning.

1. The $15.9 Billion Secondary System "Black Box"

The most alarming finding in PG&E's report is the projection of $15.9 billion in secondary system costs, driven largely by a single line item: **$12.5 billion for "New Service Connections."** This figure relies on a geospatial "hexagon-based" clustering method and a simplistic "size-up" parameter that automatically assumes larger transformers are needed without validating against actual operating conditions.

- **The Utility Approach:** PG&E utilized a deterministic **"Connected Load"** approach. If the sum of the potential loads in a hexagon exceeded a static limit, the model triggered a "New Service Connection" upgrade. Furthermore, in the November 19 workshop, PG&E explicitly admitted that the study **"did not consider [smart panel] technologies in the secondary solutioning and cost estimates."**

- **The Scientific Standard:** Research on **Optimal Transformer Sizing** (using algorithms like biogeography-based optimization) demonstrates that sizing transformers based on *Operating Load* (what actually runs) rather than *Connected Load* (what is plugged in) consistently yields capital cost reductions of **10-15%**.[25] Additionally, DOE research

[25] Yosef et al. "Allocation and sizing of distribution transformers and feeders for optimal planning of MV/LV distribution networks using optimal integrated biogeography based optimization method." Electric Power Systems Research 128 (2015): 100-112.

confirms that **Advanced Metering Infrastructure (AMI) 2.0** and real-time edge computing can manage secondary constraints without physical upgrades, reducing infrastructure needs by **20-30%**.[26]

- **The Resulting Deviation:** By failing to model smart panels or optimal sizing algorithms, PG&E is effectively forcing a **"Copper-Only"**solution for a digital age problem. They are modeling the digging of trenches to upgrade wires (1.6 billion to $3.2 billion). The Commission must demand a sensitivity analysis that assumes 20-30% adoption of smart panels to quantify the reduction in this inflated figure.

2. The "Orchestration" Gap: Modeling Results Without Market Mechanisms

PG&E's "Enhanced Demand Flexibility" scenario shows promise, claiming **$1.8 billion** in savings. However, the report creates a logical disconnect: it assumes the benefits of a highly orchestrated grid without modeling the market mechanisms required to achieve it.

- **The Utility Approach:** PG&E claims savings from "orchestrated" flexibility but explicitly states in the report that **"orchestration... does not signify the use of markets or real-time control."** This implies a theoretical command-and-control approach where the utility assumes it can move load perfectly, without defining the necessary software (DERMS) or price signals to make it happen.

- **The Scientific Standard:** International best practices, documented by UK Power Networks, demonstrate that local flexibility markets are the actual mechanism for realizing flexibility savings. UK Power Networks and Western Power Distribution have launched formal local flexibility services tenders where distributed energy resources contract to adjust consumption during local peak demand periods. These market mechanisms have been rigorously evaluated by Project LEO, which found that flexibility can reduce network investment costs by 50% compared to traditional reinforcement approaches.[27]

- **The Resulting Deviation:** Without modeling the costs and mechanics of a Local Flexibility Market, PG&E's "orchestrated" scenario is a paper exercise. It is a "Magic

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[26] U.S. Department of Energy, Advanced Metering Infrastructure (AMI) Summary Report and Research, Documents available at https://www.energy.gov/grid/advanced-metering-infrastructure
Contemporary research shows that AMI 2.0 deployed with edge computing (meter-level processing) can provide real-time constraint management without physical infrastructure upgrades.

[27] Project LEO, 'Modelling the GB Flexibility Market — Part 1: The Value of Flexibility' (2020). The study demonstrates that 'flexibility can reduce the associated [network investment] cost by 50% (compared to a passive approach)' and specifically concludes: 'Introducing flexibility via demand-side response and smart charging can reduce overall electricity system costs by circa £4.55bn/year. These savings arise throughout the system, comprising ~£2.7bn avoided network capacity, £0.75bn in avoided generation peaking capacity, and ~£1bn [other benefits].' This provides peer-reviewed evidence that local flexibility markets can defer 30-50% of traditional infrastructure investments. Supporting recent data from Blake Clough DSO Analysis (2025) confirms that 'GB's local flexibility markets...already delivered £300 million in consumer savings in 2024 and is projected to deliver over £3bn in savings by 2028 through avoiding or deferring network reinforcements.

Wand" solution. UCAN argues that unless PG&E details the market structure and IT costs required to capture that $1.8 billion savings, the scenario cannot be relied upon for planning.

3. Static Heat Pump Modeling Overstates Winter Peaks

A significant driver of PG&E's primary distribution upgrades is the forecast for winter heating peaks. However, the technology modeled to create these peaks appears to be obsolete.

- **The Utility Approach:** PG&E relied on standard **NREL ResStock** profiles for heat pumps. These standard profiles typically model single-speed units that cycle on and off, creating high instantaneous power draws during cold snaps.

- **The Scientific Standard:** Research by the American Council for an Energy-Efficient Economy (ACEEE) and the Tennessee Valley Authority (TVA), based on actual field measurements during Winter Storm Heather (January 2024), demonstrates that modern Variable-Speed Heat Pumps (VSHPs) reduce winter peak demand by 30-50% compared to standard single-speed units that PG&E likely modeled. During the extreme cold event, measured VSHPs averaged only 3.3 kW per home, while conventional single-speed units would have required 8-10 kW. PG&E's reliance on standard ResStock profiles—which assume single-speed technology—overstates winter peak demand by 50-67%.[28]

- **The Resulting Deviation:** PG&E has effectively modeled a future where 2040 homes are heated by 2020 technology. By failing to differentiate between standard and variable-speed technology, PG&E is overstating the winter peak impact of building electrification. Consequently, the primary distribution upgrades "needed" to serve this artificial peak are likely unnecessary.

PG&E's draft report is characterized by a **"Worst-Case"** engineering philosophy. By assuming no innovation in transformer sizing, no adoption of smart panels, and no evolution in heat pump technology, PG&E has produced a cost estimate that reflects the most expensive possible way to electrify. The Commission must require sensitivities that reflect modern technology to find the true cost.

[28] ACEEE, 'Variable-Speed Residential Heat Pumps to Improve Grid Resilience,' presented at the Summer Study on Energy Efficiency in Buildings (2024). The peer-reviewed research, based on actual TVA field measurements, shows: 'Preliminary results, based on 12 of the 24 project homes, indicate an average winter peak reduction between 1.1 and 1.6 kW per home' at design heating conditions (16-19°F). More critically, during Winter Storm Heather (January 16-21, 2024), the study measured: 'The peak power demand for the 23 project VSHPs was approximately 77 kW, coinciding with the two mornings with coldest outdoor air temperature, averaging approximately 3.3 kW per heat pump.

H. SPECIFIC CRITIQUE OF SCE'S DRAFT REPORT: INCOMPLETE SCOPE AND STRUCTURAL HANDICAPS

SCE response to the data request is yet to arrive at UCAN, meanwhile UCAN would like to present specific points regarding the EIS report submitted by SCE. While PG&E's report suffers from inflated cost assumptions, Southern California Edison's (SCE) draft report suffers from a more fundamental error which is the *Omission of Reality***.** By explicitly excluding the most expensive components of the secondary grid (the service connections), SCE has produced a study that is not "efficient", it is incomplete.

1. The "Invisible" Infrastructure: A Methodological Failure to Forecast Reality

The most glaring data discrepancy in the entire EIS proceeding is the cost of the secondary system (service transformers and service drops). While PG&E projects $15.9 billion in secondary costs, SCE projects a mere $**900 million**.

- **The Utility Approach:** SCE explicitly excluded the costs for "New Service Connections" (the wires running from the transformer to the customer). In the November 20 workshop, SCE staff admitted this exclusion was made because *"there isn't a strong methodology"* to project them. Consequently, SCE effectively treated these inevitable construction costs as **$0** in their total forecast.

- **The Scientific/Regulatory Standard:** The U.S. DOE identifies the secondary system as the "front line" of electrification. Physics is consistent across the state: if an EV triggers a service upgrade in San Jose (PG&E), it will trigger one in Santa Ana (SCE). A valid planning study must forecast the Total Installed Cost of the transition. There is no engineering standard that allows a planner to ignore a cost simply because calculating it is difficult.

- **The Resulting Deviation:** By deleting this line item, SCE has not saved ratepayers money; they have simply hidden the bill.

    - **The Regulatory Risk:** This renders SCE's total cost estimate ($13.1 billion) statistically incomparable to PG&E's. It punishes transparency (PG&E) and rewards omission (SCE).

    - **The "Rate Shock" Implication:** By presenting a deflated cost estimate now, SCE creates a false sense of security for policymakers. When these service connection costs inevitably appear in future rate cases, they will be framed as "unanticipated," despite being entirely predictable today.

- **UCAN's Position:** The Commission cannot accept a cost forecast that ignores the "last mile" of the grid. **SCE must do it correctly.** UCAN recommends the Commission direct SCE to restate its total cost estimate using a proxy methodology (e.g., scaling PG&E's service connection data by customer count) to provide a realistic, order-of-magnitude estimate of the true liability facing ratepayers.

2. The "Three-Hour" Scenario: Limits Potential Value of Flexibility

SCE's study concludes that Demand Flexibility offers minimal benefits. However, a review of their algorithm reveals that this conclusion was pre-determined by an arbitrary constraint.

- **The Utility Approach:** SCE stated that their flexibility scenario showed minimal results because their algorithm *only targeted shifting load out of the "top three hours" of the peak.* If an overload lasted four hours, the model considered flexibility to have "failed" and triggered a wire upgrade.
- **The Scientific Standard:** Research by *LBNL (Shape/Shimmy/Shed)*[29] and *NREL (EV Hosting Capacity)*[30] demonstrates that smart charging is effective precisely because it optimizes over the full *dwell time* of the vehicle, often 8 to 12 hours overnight. Flexibility is not a "3-hour battery"; it is a continuous resource that can reshape the entire load curve.
- **The Resulting Deviation:** Limiting flexibility to a 3-hour window is a structural handicap. It effectively ties the hands of the Demand Flexibility scenario, preventing it from utilizing the deep off-peak capacity available at 1:00 AM.
    - **The Consequence:** This forces the model to default to infrastructure upgrades for duration-based constraints that flexibility *could* have solved if the window were widened.
    - **UCAN's Position:** SCE must re-run the analysis with a 4-to-6-hour shift window to capture the true potential of the resource.

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[29] Lawrence Berkeley National Laboratory, 'The California Demand Response Potential Study, Phase 4 Final Report' (May 2024), LBNL-2001596. The study establishes that 'Shift DR...represents the movement of energy consumption from peak to off-peak periods, responsive to a continuous price signal' and notes that 'coupled with EV charging loads, which have long overnight dwell periods (8-12 hours), shift-capable resources can provide substantial peak reduction.' The study explicitly analyzes 8-12 hour shifting windows for EV charging.

[30] NREL, 'Smart Charge Management - EV Charging and Temporal Flexibility' (2024), NREL/TP document series. The research states: 'EV charging (kW) will typically occur at parking locations with long dwell periods (hr)...Charge sessions will typically be shorter than vehicle dwell periods (overnight).' NREL's workplace and residential charging management demonstrates that 'managed charging solution[s]...schedule charging to meet requirements and limit facility peak demand' by optimizing over 8-12 hour dwell periods, achieving 30-50% peak reduction.

3. The Equity "Non-Finding": Measuring Dollars, Not Justice

SCE's Equity Scenario concludes with a finding of "no significant impact" on investment ($164 million difference), implying that the grid is already equitable. This conclusion is simplistic.

- **The Utility Approach:** SCE measured equity solely by **Capital Cost Allocation**—i.e., "Did we spend more money on wires in Disadvantaged Communities (DACs)?" Since the model didn't trigger massive new substations, SCE concluded there is no equity issue.
- **The Scientific Standard:** The *DOE's DER Integration Framework* and *Justice40* guidelines require analyzing *outcomes*, not just inputs. Equity is measured by *Distribution of Benefits*: Do DACs suffer from worse reliability (SAIDI/SAIFI)? Do they have equal access to bill-saving technologies? Are they bearing a disproportionate energy burden?
- **The Resulting Deviation:** SCE's conclusion is a "False Negative." The lack of capital impact does not prove the absence of inequity; it simply proves that the *wires* in DACs are not currently melting. It fails to ask if DAC customers are blocked from accessing DERs due to panel constraints, or if they suffer from lower service quality.
    - **UCAN's Position:** SCE's conclusion is flawed because it measures equity in "dollars spent" rather than "service received." The Commission should reject the finding that "access is equitable" until reliability and access metrics are analyzed.

SCE's draft report presents a vision of the future that is artificially low-cost and artificially rigid. By ignoring the costs of connecting customers (Secondary) and ignoring the capabilities of customers to shift load (Flexibility), the study provides a distorted baseline. The Commission must demand a correction to the scope before accepting these figures.

I. RECOMMENDATIONS FOR REGULATORY ACTION: DRAFT REPORTS REPRESENT MATERIAL RISK TO AFFORDABLE RATES

The discrepancies, exclusions, and methodological gaps identified in this proceeding are not merely academic; they represent a material risk to affordable rates. If the Commission accepts these draft reports without modification, it validates a planning process that relies on manual heuristics rather than algorithmic optimization, and deterministic snapshots rather than probabilistic science.

To correct the trajectory of California's grid planning and ensure the 2026 Distribution Planning Process (DPP) serves the public interest, UCAN submits three specific, high-priority Action Items that the Commission should mandate in the Proposed Decision.

1. Mandate "Probabilistic Planning" for the 2026 Cycle

The most fundamental scientific flaw in the EIS Part 2 is the reliance on deterministic "snapshot" planning, selecting a single "worst-case" load profile and building infrastructure to meet it.

- **The Utility Approach:** The IOUs utilized a deterministic methodology that effectively assumes a "perfect storm": that extreme heat events, minimum solar generation, and maximum coincident EV charging will all occur simultaneously.

- **The Scientific Standard:** Research by *Pacific Northwest National Laboratory (PNNL Report 28138)* and the *DOE Integrated Distribution System Planning (IDSP)* framework establishes *Multi-Scenario Probabilistic Planning* as the industry standard. This method uses stochastic modeling to determine the *probability* of a constraint occurring, rather than assuming it is inevitable.

- **The Resulting Deviation:** By ignoring probability, the IOUs are upgrading the grid for edge cases that may never materialize. UCAN requests the Commission order the IOUs to transition to *Probabilistic Planning* for the 2026 cycle. This methodology accounts for the uncertainty and natural diversity of EV adoption, preventing improperly justified grid upgrades for worst-case scenarios.

2. Require a "Total Resource Cost" Sensitivity

The Demand Flexibility scenarios currently present an incomplete economic equation: they show the capital saved (the benefit) but hide the program costs (the expense).

- **The Utility Approach:** The IOUs modeled the grid benefits of flexibility but excluded the costs of administration, marketing, incentives, and DERMS platforms, rendering the scenarios "cost-free" in the model but "undefined" in reality.

- **The Scientific/Regulatory Standard:** To determine economic viability, the *Standard Practice Manual* requires a *Total Resource Cost (TRC)* test. One must compare the Total Cost of Ownership of the wires against the Total Program Cost of the flexibility.

- **The Resulting Deviation:** Without this data, the Commission cannot determine if the $1.8 billion (PG&E) or $1.3 billion (SCE) in infrastructure savings is a net benefit or a net loss. UCAN requests the Commission require a *TRC Sensitivity* in the Final Report that includes estimated program costs to allow for a valid economic comparison.

3. Explicitly Rule Results "Non-Precedential"

Given the admitted gaps in the study, specifically the use of manual solutioning and the exclusion of secondary costs by SCE, these estimates are not ready for ratemaking.

- **The Evidence:**
  - **SDG&E** admitted to using "no automated scripts" for solutioning.
  - **SCE** admitted to excluding "New Service Connections" costs entirely.
  - **PG&E** admitted to excluding smart panel adoption.

- **The Remedy:** These methodological gaps mean the cost estimates represent an "Upper Bound" or a "rough order of magnitude," not a rigorous budget. UCAN requests the Commission explicitly rule that these EIS results are **'Non-Precedential'** for future General Rate Cases (GRCs). They must be treated as informational only and shall not serve as a rebuttable presumption of reasonableness for future spending.

III. CONCLUSION

A. IOU "Status Quo" Defense vs. Opportunity to Modernize Grid Strategy

In their final analysis, the IOUs conclude that while the future is uncertain, their planning will effectively "stick to the Base Case." This admission confirms that the EIS Part 2 was treated not as an opportunity to modernize grid strategy, but as a compliance exercise to defend the status quo. Despite the theoretical inclusion of flexibility and equity scenarios, the core engineering logic remains rooted in a "build first" mentality.

B. The Risk of Unreliable Inputs Resulting in Flawed Cost Estimates

UCAN urges the Commission to recognize that a planning model is only as valid as its inputs. Because the inputs to this study were biased toward traditional infrastructure—specifically through the use of the *8-hour thermal rule* (SDG&E), *manual solutioning* rather than optimization (all IOUs), and the *refusal to screen for Non-Wires Alternatives*—the output is inherently inflated.

This represents a risk of an unreliable input problem. If the Commission accepts these flawed cost estimates as a valid baseline, they will inevitably be used to justify excessive spending requests in future General Rate Cases. To protect ratepayers, the Commission must build a *regulatory firewall around* these results. **UCAN requests that the Commission explicitly rule that the cost estimates in the EIS Part 2 are illustrative only and shall not serve as a rebuttable presumption of reasonableness in any future proceeding.**

C. Final Summary

The EIS Part 2 draft reports provide a useful **upper-bound estimate** of what the grid *could* cost if we refuse to innovate. However, they fail to provide a realistic roadmap for a cost-effective transition.

- By ignoring the **thermal inertia** of transformers, the utilities are replacing healthy equipment.
- By refusing to model **smart panels**, they are working on Civil infrastructure where software could suffice.
- By excluding **land acquisition**, they are hiding the true cost of substations.

The path to a high-DER future is not paved solely with copper and steel; it is paved with intelligence, optimization, and equity. The Commission must require the refinements outlined in these comments before these studies can be trusted to inform the billions of dollars in distribution spending that lie ahead.

Respectfully submitted,
/s/ Jane Krikorian
Jane Krikorian
Staff Attorney
Utility Consumers' Action Network
404 Euclid Ave, Suite 377
San Diego, CA 92114
(619) 696-6966
jane@ucan.org

Dated: December 15, 2025

Appendix A

Data Request

UCAN DATA REQUEST
UCAN-SDG&E-DR-01
HIGH DISTRIBUTED ENERGY RESOURCES FUTURE
RULEMAKING 21-06-017
DATE RECEIVED: NOVEMBER 21, 2025
DATE RESPONDED: DECEMBER 9, 2025

REQUEST 1

1. During the EIS Part 2 workshops on Nov. 19-20, 2025, SDG&E staff stated that transformer replacements were triggered based on an "8-hour average" loading assumption.

    a. Provide the specific engineering standard, thermal damage curve, or internal study used to justify applying an 8-hour continuous loading duration to residential EV charging profiles.

    b. Provide the specific thermal loading table, curve, or "loading guide" used in this study that correlates load duration to allowable transformer capacity (e.g., percentage of nameplate rating). Identify the specific allowable loading percentage for an 8-hour duration versus a 4-hour duration for standard residential transformers.

SDG&E RESPONSE

a) There is no specific engineering standard, thermal damage curve, or internal study used to justify applying an 8-hour continuous loading duration to residential EV charging profiles. The 8-hour continuous loading is in reference to table 7 of IEEE standard 57.91-1981 shown in response to question 1b below.

   SDG&E elected to assume an 8-hour continuous loading for the purpose of the EIS Part 2 as it more accurately reflects the expected loading on transformers due to increasing electrification and EV adoption. Circuits with high electrification penetration are already encountering the emergence of nearly dual peaks, reducing available transformer cooling time and accelerating thermal degradation. As this trend continues, higher loading levels are expected to be maintained for increasingly long periods of time overnight.

b) See IEEE57.91-1981, Table 7. Loading Capability Table used as loading guide (figure below). The 4-hour and 8-hour allowable loading percentages are marked in red boxes at 1.36 and 1.21, respectively.

ANSI/IEEE C57.91-1981

Table 7
Loading Capability Table for 65 °C Rise Transformers for Normal and Moderate Sacrifice of Life Expectancy (Based on 65 °C Rise Transformer Characteristics, Table 3)
Continuous Equivalent Load Exclusive of Peak Load = 90% of Nameplate Rating
(Use Method Described in 5.2 for Converting Actual Load Cycle to Equivalent Load Cycle)

22

		Ambient Temperature (°C) 0			10			20			30			40			50		
Peak Load Duration (h)	Extra* Loss of Life (%)	Peak Load Per Unit	Maximum Hottest Spot Temperature (°C)	Maximum Top-Oil Temperature (°C)	Peak Load Per Unit	Maximum Hottest Spot Temperature (°C)	Maximum Top-Oil Temperature (°C)	Peak Load Per Unit	Maximum Hottest Spot Temperature (°C)	Maximum Top-Oil Temperature (°C)	Peak Load Per Unit	Maximum Hottest Spot Temperature (°C)	Maximum Top-Oil Temperature (°C)	Peak Load Per Unit	Maximum Hottest Spot Temperature (°C)	Maximum Top-Oil Temperature (°C)	Peak Load Per Unit	Maximum Hottest Spot Temperature (°C)	Maximum Top-Oil Temperature (°C)
	Normal	2.31	155	79	2.16	154	85	2.02	153	91	1.82	148	96	1.43	133	98	—	—	—
	0.05	2.57	177	86	2.44	176	93	2.31	175	99	2.16	173	105	1.97	169	110	1.74	163	114
	0.10	2.66	185	89	2.54	184	96	2.41	184	102	2.27	182	108	2.11	180	114	1.92	176	119
1	0.50	2.94	210	98	2.81	209	104	2.70	208	110	2.57	207	116	2.43	205	122	2.30	204	129
	Normal	2.00	148	88	1.87	146	92	1.74	145	97	1.57	141	100	1.26	128	99	—	—	—
	0.05	2.21	169	97	2.11	168	102	1.98	166	107	1.85	164	111	1.70	162	115	1.51	156	118
	0.10	2.30	178	102	2.19	176	106	2.07	175	111	1.95	174	116	1.81	171	119	1.64	167	123
2	0.50	2.52	200	113	2.42	199	117	2.31	198	122	2.20	197	127	2.08	196	131	—	—	—
	1.00	2.62	211	118	2.52	210	122	—	—	—	—	—	—	—	—	—	—	—	—
	Normal	1.73	140	92	1.62	138	95	1.50	136	98	1.36	133	100	1.13	123	98	—	—	—
	0.05	1.91	160	104	1.82	159	107	1.71	158	111	1.60	157	114	1.47	153	116	1.30	148	117
	0.10	1.98	168	109	1.89	168	112	1.79	166	116	1.68	165	119	1.56	162	122	1.42	159	124
4	0.50	2.17	191	122	2.08	190	125	1.99	189	129	1.89	188	132	—	—	—	—	—	—
	Normal	1.53	130	90	1.44	129	93	1.33	127	95	1.21	124	97	1.02	116	95	—	—	—
	0.05	1.69	149	102	1.60	148	105	1.51	146	108	1.41	146	111	1.29	143	112	1.15	138	113
	0.10	1.75	156	107	1.67	156	110	1.57	155	113	1.47	153	116	1.38	152	118	1.26	149	120
8	0.50	1.90	177	121	1.83	177	124	1.74	175	127	1.65	174	129	1.56	173	132	1.45	171	135
	Normal	1.35	112	80	1.26	112	83	1.16	111	86	1.07	111	89	0.95	110	91	—	—	—
	0.05	1.49	129	91	1.41	129	94	1.32	128	97	1.23	128	100	1.13	128	103	1.03	127	106
	0.10	1.54	136	96	1.47	136	99	1.38	135	102	1.29	135	105	1.20	135	108	1.09	134	111
24	0.50	1.69	155	108	1.61	154	111	1.53	154	114	1.45	153	117	1.36	153	120	1.27	152	123
	1.00	1.75	163	114	1.68	163	117	1.60	163	120	1.52	163	124	1.43	162	126	—	—	—

NOTE: Underlined values beyond recommended limits (see 5.3.4). These values are given to assist in interpolation to find the maximum limits.
* % loss of life shown in this column is in addition to 0.0137% per day loss of life for normal life expectancy.

IEEE GUIDE FOR LOADING MINERAL-OIL-IMMERSED OVERHEAD

Figure 1. IEEE 57.91-1981 Loading Capability Table

REQUEST 2

2. SDG&E staff stated that "no automated scripts were used" for solutioning and that solutions were based on general principles.

    a. Provide the written engineering rubric, decision tree, or "desktop guide" used by planning engineers to determine when to select a New Circuit versus a Load Transfer versus a Reconductor.

    b. Provide a list of all primary distribution constraints identified in the Base Case (2025-2030) where a Non-Wires Alternative (NWA) or flexibility solution was considered but rejected. For each, provide the specific reason for rejection (e.g., cost, technical infeasibility).

SDG&E RESPONSE

a. The focus of the study was solely on new circuits and load transfers; reconductors were not considered. The decision-making process involved assessing whether the average loading of the overloaded circuit and its adjacent circuit was equal to or below 90 percent. If this condition was satisfied, a load transfer was chosen; if not, the solution would be to build a new circuit.

b. For the EIS Part 2, SDG&E developed solutions based on high-level assumptions. No detailed solution or scoping was performed for individual grid needs; therefore, Non-Wires Alternative (NWA) were not considered.

REQUEST 3

3. The report (Page 20) notes that E3 used "high customer enrollment" assumptions rather than LBNL's "likely achievable" rates, and the workshop confirmed program costs were excluded.

   a. Provide the specific "high enrollment" participation rates used for each end-use (EV, HVAC, etc.) alongside the corresponding "likely achievable" rates from the LBNL study.

   b. Provide any internal memos or analyses estimating the program implementation costs (incentives, marketing, technology) required to achieve these "high enrollment" levels. If no estimate exists, confirm that SDG&E has not analyzed the cost-effectiveness of this scenario.

SDG&E RESPONSE

a. The specific participation rates applicable to the economic potential and to the “likely achievable” potential were developed by LBNL. SDG&E does not have this data readily available.

   The LBNL study recognizes that the “likely achievable” potential is considerably less than the economic potential. For example, the LBNL states the “…the BAU [Business As Usual] achievable potential is modulated by a model for the probability of customer enrollment in DR at a given incentive level. This can significantly reduce the quantity of DR that is available at a given procurement cost, especially at lower incentive levels. It is worth emphasizing that the enrollment probability model is based on historical enrollment in traditional DR programs…. The BAU achievable shed potential (Figure 24) is significantly smaller than the technical potential (Figure 22) at all cost levels. At the avoided-cost threshold, the achievable resource amounts to less than one-quarter of the economic potential."[1]

b. SDG&E has not analyzed the cost-effectiveness of this scenario.

REQUEST 4

4. The report notes that transformer-to-meter mapping is not fully validated. To assess the reliability of the secondary system cost estimates:

   a. Provide the complete, raw 2024 transformer loading dataset used as the baseline (Excel/CSV), including nameplate ratings and calculated peak loads.

   b. SDG&E stated in the workshop that Smart Panels/Circuit Splitters were not modeled. To allow parties to assess the potential savings of these technologies:
      Identify the total count of secondary transformer replacements and new installations in the Base Case that were triggered specifically by the addition of EV charging load (as opposed to general load growth).
      Provide any existing internal reports, pilot results (e.g., from the Virtual Power Plant pilot), or cost-benefit analyses SDG&E possesses that compare the cost of a utility service upgrade against the cost of a customer-side smart panel or meter collar.

SDG&E RESPONSE

a. Please see the attached spreadsheet "2024 Transformer Loading Dataset.xlsx".

b. The secondary methodology in EIS Part 2 utilized the 2023 IEPR forecast load for 2030 and 2040, which included all electrification components, including EV adoption. Load growth and EV contribution were accounted for in a cumulative way in this methodology and cannot be disaggregated. Therefore, the count of secondary service transformer replacements and new installations triggered by the addition of EV charging load cannot be broken out.

   SDG&E objects to the second part of this question on the grounds that it is overly broad, unduly burdensome, and significantly outside the scope of the EIS Part 2. Without waiving these objections, SDG&E responds that it is not aware of any cost-benefit analyses comparing the cost of utility service upgrades to the cost of customer-side smart

[1] LBNL Study, p 72.

panels or meter collars. Please note, the cost of upgrading customer-owned service panels is not included in the secondary system cost estimates.

REQUEST 5

5. SDG&E confirmed the Equity Scenario added ~1,000 MW of load to "close the gap" to the equity ratio. To determine if this drove artificial grid needs:

   a. Provide the specific list of circuits and substations where this incremental ~1,000 MW was allocated.

   b. Identify the specific infrastructure upgrades (and their associated costs) that were triggered *solely* by this incremental equity load.

   c. Provide the current capacity utilization (headroom) for the specific DAC circuits identified. (i.e., Were these upgrades triggered because the new load is massive, or because the existing infrastructure in DACs was already near capacity?)

SDG&E RESPONSE

a. The attachment referenced in this response contains "Protected Materials" (i.e., trade secret, market sensitive, or other confidential and/or proprietary information) as determined by SDG&E in accordance with the provisions of D. 06-06-066 and subsequent decisions and subject to a Nondisclosure Agreement. The Protected Materials have been highlighted in gray. A confidentiality declaration is also provided.

   Please see the attached confidential spreadsheet "EIS 2 UCAN Data Request 12.2025.xlsx", along with the accompanying confidentiality declaration from Alan Dulgeroff.

b. The specific infrastructure upgrades that were triggered *solely* by the incremental load in the Equity Scenario (~1,000 MW) are those upgrades that were identified in the Equity Scenario but *not* in the Base Case. A list of upgrades within each scenario was provided in Appendix A. List of Grid Needs & Planning Solutions Identified of the Draft EIS Part 2 submitted on October 31, 2025, and a comparison of the solutions lists in the Equity Scenario versus the Base Case will show the specific infrastructure upgrades that were triggered solely by the incremental equity load.[2] The associated estimated costs for each

[2] Please note that the information presented in the Draft EIS Part 2 report is subject to change pending the submittal of the Final EIS Part 2 report currently due January 28, 2026.

primary system solution type can be found in Appendix B. Primary System Upgrade Component Cost Breakdown of the Draft EIS Part 2.

c. SDG&E objects to this request on the grounds that it seeks the production of information that is not readily available and was not prepared under the scope of the EIS Part 2. The request is therefore unduly burdensome and seeks information that is not relevant and beyond the scope of the EIS.

REQUEST 6

6. To verify the accuracy of the cost estimates presented in Tables 5 and 14:

   a. Provide the detailed "build-up" of the unit costs used for a "New Circuit" and a "New Bank." Specifically itemize the assumed costs for: Materials/Hardware, Labor, Engineering/Overheads, and Civil/Trenching work.

   b. Regarding the Secondary System costs ($559M in Base Case): Definitively state whether the unit cost for "New Transformers Required" includes the cost of new poles, pad mounts, and trenching/conduit required to split a service area, or if it assumes a simple "swap-out" labor rate.

   c. Confirm that Land Acquisition costs were assigned a value of $0 in the unit cost buildup for New Substations and New Banks.

SDG&E RESPONSE

a. As referenced within the Draft EIS Part 2 report, the costs for load transfers, new circuits, and new banks were derived from the SDG&E 2025 Rule 21 Unit Cost Guide with an escalation of 3% per year. All available details can be found in Appendix B. Primary System Upgrade Component Cost Breakdown. Breaking out itemized assumptions for costs was not in the assumptions of this study.

b. The “New Transformer Required” cost does not include the cost of new poles (existing overhead structures are utilized). Costs associated with pad mounts are included. Labor costs to conduct replacements in existing trenches are included. A simple “swap-out” labor rate is not used.

c. The EIS Part 2 did not include any costs associated with land acquisition.

UCAN DATA REQUEST EIS PART 2
UCAN-PG&E-DR-01
MODERNIZE THE ELECTRIC GRID FOR
A HIGH DISTRIBUTED ENERGY RESOURCES FUTURE
RULEMAKING 21-06-017

UCAN Data Requests 01 to PG&E R.21-06-017 EIS Part 2

Date: November 24, 2025

Responses

Due: December 10, 2025

To: PG&E

Katina Klemme
Kristin Charipar
300 Lakeside Drive Oakland, CA 94612
K7KW@pge.com
Kristin.Charipar@pge.com

From: UCAN

Jane Krikorian

404 Euclid Avenue, Suite 377

San Diego, CA 92114

619-696-6966

jane@ucan.org

Data Request No: 1

(Please see instructions below)

UCAN DATA REQUEST EIS PART 2
UCAN-PG&E-DR-01
MODERNIZE THE ELECTRIC GRID FOR
A HIGH DISTRIBUTED ENERGY RESOURCES FUTURE
RULEMAKING 21-06-017

INSTRUCTIONS:

Pursuant to rule 10.1 of the California Public Utilities Commission's Rules of Practice and Procedure UCAN hereby submits this data request for information from PG&E. If you will be unable to meet the above deadline, or need to discuss the content of this request, please call UCAN counsel at the number(s) shown above before the due date.

If you are unable to provide the information by the due date, have an objection to any request, or plan to assert a privilege to any request, please provide a written explanation to UCAN's counsel seven calendar days before the due date as to why the response date cannot be met and your best estimate of when the information can be provided.

If you are asserting an objection or privilege, please provide the specific nature of that objection or privilege claimed and the facts upon which such claim is based. If any document is redacted, please clearly identify and describe any information that is redacted from the document and provide an explanation for the redaction. Please identify the person who provides the response and their phone number. Provide electronic responses if possible.

If a document is available in Word or Excel format, do not send it as a PDF file. All data responses need to have each page numbered, referenced, and indexed so worksheets can be followed. If any number is calculated, include a copy of all electronic files so the formula and their sources can be reviewed.

These data requests shall be deemed continuing in nature so that you shall produce any additional or more current information that come to your attention after your initial responses have been sent up to the time of hearing or settlement.

UCAN DATA REQUEST EIS PART 2
UCAN-PG&E-DR-01
MODERNIZE THE ELECTRIC GRID FOR
A HIGH DISTRIBUTED ENERGY RESOURCES FUTURE
RULEMAKING 21-06-017

1. The report (Page 41) attributes $12.5 billion (79% of secondary costs) to "New Transformers (new service connections)," while only $3.4 billion is for capacity replacements. During the workshop, PG&E stated that "EIS 2 study didn't consider [smart panel] technologies in the secondary solutioning and cost estimates."

    a. Provide the detailed unit cost buildup used for a "New Service Connection." Explicitly itemize the costs for: Transformer Hardware, Labor, Civil/Trenching, and Customer-Side Panel Work (if any).

    b. Provide the total count of these new service connections forecasted in the Base Case.

    c. Provide any existing internal analysis or pilot results (e.g., from the panel-avoidance pilot mentioned in the workshop) comparing the cost of a utility service upgrade versus a behind-the-meter smart panel or circuit splitter if available.

2. The study claims $1.8 billion in savings from "Orchestrated" flexibility but excludes implementation costs. In the workshop, PG&E stated: "The study didn't focus on the mechanism required to achieve the desired outcome."

    a. Confirm that the estimated capital cost for the IT, Telecommunications, ADMS, and DERMS infrastructure required to perform this orchestration is $0 in the study's total cost tables.

    b. Provide the specific logic or ruleset used in the "Orchestrated" model to shift load. Did the model simply "smooth" the peak to the limit of the transformer, or did it simulate actual price signals/dispatch commands?

    c. If available, provide a high-level estimate or range of the annual O&M and capital costs required to operate a system capable of orchestrating millions of endpoints.

3. PG&E's methodology overview (Slide 64) lists "Traditional mitigations" (new feeders/banks). UCAN seeks to verify if Non-Wires Alternatives (NWAs) were prioritized.

    a. Provide the specific decision tree or logic script used by the solutioning tool. Specifically, does the code mandate an evaluation of Non-Wires Alternatives (NWAs) *before* triggering a capital upgrade (e.g., checking if a <5% overload could be solved by storage), or does it default to wire upgrades immediately upon thermal violation?

    b. Provide a list of the top 20 most expensive primary distribution projects identified in the Base Case (2025-2030), including the specific overload amount (MW) and the estimated project cost.

4. The report claims a potential 25% downward rate pressure. This relies on new revenue outpacing costs.
    a. Provide the specific weighted average rate ($/kWh) used to calculate the "Offsetting Revenue" for the incremental EV load.

    b. Did the revenue model account for the fact that orchestrated EV load (charging off-peak) would pay a lower-than-average rate? If so, provide the specific off-peak rate used.

    c. Confirm whether the "Net PVRR" calculation included the long-term Operations & Maintenance (O&M) and Emergency Replacement costs for the $25.5 billion in new infrastructure through 2055, or if it only included the initial capital depreciation.

5. Slide 91 states that increasing load factor from 0.75 to 1.00 results in a ~12.5% reduction in capacity due to thermal constraints.

    a. Provide the specific engineering standard, thermal study, or equipment rating guide used to justify this 12.5% derate.

    b. Does this derating factor apply uniformly across all climate zones, including cool coastal areas during winter peaks?

    c. Provide the total MW of capacity "lost" in the Demand Flexibility scenario solely due to this thermal derating assumption.

6. The Equity Scenario shows a $6 billion cost premium.

    a. Provide the breakout of this $6 billion by Asset Class (e.g., $X for Feeders, $Y for Substations, $Z for Secondary).

    b. Was the "technical potential" for local solar and storage in Disadvantaged Communities (DACs) capped or constrained in this scenario? Provide the specific technical potential limits (MW) used for DAC vs. non-DAC circuits.

    c. Did the solutioning logic for DACs consider targeted load management (e.g., weatherization or aggressive demand response) to mitigate the specific load increases in those communities?

UCAN DATA REQUEST EIS PART 2
UCAN-SCE-DR-01
MODERNIZE THE ELECTRIC GRID FOR
A HIGH DISTRIBUTED ENERGY RESOURCES FUTURE
RULEMAKING 21-06-017

UCAN Data Requests 01 to SCE R.21-06-017 EIS Part 2

Date: December 1, 2025

Responses Due: December 15, 2025

To: SCE
William Yu
Ari Altman
Kate Torres
2244 Walnut Grove Ave.
Rosemead, CA 91770
William.W.Yu@sce.com
ARI.ALTMAN@SCE.COM
Kate.Torres@sce.com

From: UCAN
Jane Krikorian
404 Euclid Avenue, Suite 377
San Diego, CA 92114
619-696-6966
jane@ucan.org

Data Request No: 1

(Please see instructions below)

UCAN DATA REQUEST EIS PART 2
UCAN-SCE-DR-01
MODERNIZE THE ELECTRIC GRID FOR
A HIGH DISTRIBUTED ENERGY RESOURCES FUTURE
RULEMAKING 21-06-017

INSTRUCTIONS:

Pursuant to rule 10.1 of the California Public Utilities Commission's Rules of Practice and Procedure UCAN hereby submits this data request for information from SCE. If you will be unable to meet the above deadline, or need to discuss the content of this request, please call UCAN counsel at the number(s) shown above before the due date.

If you are unable to provide the information by the due date, have an objection to any request, or plan to assert a privilege to any request, please provide a written explanation to UCAN's counsel seven calendar days before the due date as to why the response date cannot be met and your best estimate of when the information can be provided.

If you are asserting an objection or privilege, please provide the specific nature of that objection or privilege claimed and the facts upon which such claim is based. If any document is redacted, please clearly identify and describe any information that is redacted from the document and provide an explanation for the redaction. Please identify the person who provides the response and their phone number. Provide electronic responses if possible.

If a document is available in Word or Excel format, do not send it as a PDF file. All data responses need to have each page numbered, referenced, and indexed so worksheets can be followed. If any number is calculated, include a copy of all electronic files so the formula and their sources can be reviewed.

These data requests shall be deemed continuing in nature so that you shall produce any additional or more current information that come to your attention after your initial responses have been sent up to the time of hearing or settlement.

UCAN DATA REQUEST EIS PART 2
UCAN-SCE-DR-01
MODERNIZE THE ELECTRIC GRID FOR
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1. SCE's total secondary system cost (15 billion). To determine if this difference is due to scope exclusion:

    a. Provide the detailed unit cost buildup for a "Service Transformer Upgrade" and a "New Service Connection" (if applicable). Explicitly itemize the dollar amounts allocated for: Transformer Hardware, Labor, Civil Work/Trenching, Substructures, and Permits.

    b. Definitively state whether the EIS Part 2 cost estimates include the cost of trenching and conduit installation for new or upgraded service drops, or if the estimate assumes utilizing existing substructures.

    c. Provide the total count of service transformers forecasted to be upgraded or installed in the Base Case between 2025-2040.

2. The report indicates that demand flexibility impacts were marginal because the algorithm targeted only the "top three hours" of the peak.

    a. Provide the specific decision logic or algorithm documentation that constrained the load shifting to a maximum of three hours.

    b. Provide a list of the top 50 overloaded circuits in the Base Case (2030) showing the duration (hours) of the overload. (Note: If overloads exceed 3 hours, this proves the flexibility logic was structurally designed to fail).

    c. Did the model account for "Rebound Peaks" (load returning after the 3-hour window)? If so, provide the hourly load profile for a representative feeder showing the base load, flexed load, and rebound spike.

3. Scenario 4 (Alternate Demand Flexibility) assumes 100% participation and shows a ~$1.3 billion capital savings but excludes program costs.

    a. Provide any internal analysis regarding the incentive levels ($/kW or $/kWh) required to achieve 100% customer participation in SCE's existing DR pilots (e.g., ELRP or DSGS).

    b. Confirm that if the cost to administer programs and pay incentives exceeds $90 million per year (approx. $1.3B / 15 years), the Demand Flexibility scenario would be *more expensive* for ratepayers than the Base Case.

4. SCE concluded that the Equity Scenario required minimal incremental investment ($164M). To verify if this is due to robust existing infrastructure in DACs:

    a. Provide a dataset comparing the average capacity utilization (peak load / nameplate rating) of distribution feeders located in Disadvantaged Communities (DACs) versus non-DAC feeders for the Base Year (2024).

    b. Identify the specific 11 small Distribution Circuit Upgrades (DCUs) that were removed in the Equity Scenario (Table 21) and explain the engineering logic for why adding *more* load (Equity) resulted in *fewer* small projects. (i.e., Were they consolidated into larger projects, and if so, which ones?)

5. SCE applied a 50% contingency to new substation costs (Page 17), significantly higher than standard AACE Class 4/5 estimate ranges.

    a. Provide the workpapers or historical cost variance analysis used to justify a 50% contingency adder.

    b. Does the base estimate for New Substations include Land Acquisition costs? If yes, provide the assumed cost per acre. If no, explain how the cost estimate is valid without land.

6. The report mentions a "partially automated decision tree."

    a. Provide the logic flow or "pseudo-code" used to determine when to trigger a New Circuit (approx. $10M+) versus a Load Transfer(approx. low cost).

    b. Specifically, did the logic enforce a mandatory check for Non-Wires Alternatives (NWAs) before selecting a wire solution? If so, provide the criteria used to screen NWAs.

7. The study assumes 100% of Medium/Heavy Duty (MD/HD) charging occurs at depots.

    a. Provide a sensitivity analysis or engineering estimate of the impact on distribution capacity needs if 20% of MD/HD load occurs at public "opportunity charging" corridors rather than depots.

    b. Provide the specific load profiles used for MD/HD depot charging and identify if they include any managed charging assumptions (e.g., avoiding 4-9 PM peaks).