**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking Regarding Building Decarbonization.	Rulemaking 19-01-011 (Filed January 31, 2019)

PACIFIC GAS AND ELECTRIC COMPANY (U 39 G) LESSONS LEARNED REPORT PURSUANT TO ORDERING PARAGRAPHS 3 AND 4 OF DECISION NO. 25-11-004

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Dated: January 26, 2026

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Pursuant to the California Public Utilities Commission's (Commission) Decision (D.) 25-11-004, PG&E provides its A.22-08-003 "Lessons Learned" report on its zonal electrification project at California State University Monterey Bay ("CSUMB"). As background for this report, PG&E incorporates by reference the full Commission record of its CSUMB Application (A.) 22-08-003, which can be accessed at https://docs.cpuc.ca.gov/advancedsearchform.aspx.

Ordering Paragraph 3 of D.25-11-004 issued on November 25, 2025 in A.22-08-003, requires "Within 30 days of the issuance of this decision, Pacific Gas and Electric Company shall circulate to active parties to this proceeding a draft 'lessons learned' report summarizing their policy, cost and ratepayer impacts, and operational experiences with this project." Ordering Paragraph 4 of the Decision requires "Within 60 days of the issuance of this decision, Pacific Gas and Electric Company shall incorporate party input and file a 'lessons learned' report summarizing the policy, cost and ratepayer impacts, and operational experiences with this project in Rulemaking 24-09-012 and Rulemaking 19-01-011."[1]

On December 23, 2025, PG&E served its draft "Lessons Learned" report on the service list of A.22-08-003 for comment. As of January 14, 2026, the deadline for receiving comments from interested parties, PG&E had received comments on the draft from two parties, Indicated Shippers and The Utility Reform Network (TURN). For the convenience of the Commission and

[1] D. 25-11-004, Ordering Paragraphs 3 and 4, p. 19.

all parties to R.24-09-012 and R.19-01-011, PG&E has incorporated the comments by Indicated Shippers and TURN verbatim into the attached final "Lessons Learned" report for filing and compliance with D.25-11-004.

Respectfully Submitted,

By: *<u>/s/ Jonathan D. Pendleton</u>*
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Attachment - A.22-08-003 "Lessons Learned" Report
January 26, 2026

Pursuant to D. 25-11-004, PG&E provides its A.22-08-003 “Lessons Learned” report on its zonal electrification project at California State University Monterey Bay (“CSUMB”). As background for this report, PG&E incorporates by reference the full Commission record of its CSUMB Application (A.) 22-08-003 which can be accessed at https://docs.cpuc.ca.gov/advancedsearchform.aspx as well as comments from interested parties.

I. PRACTICAL, PROCEDURAL AND REGULATORY “LESSONS LEARNED”

A. PG&E

Three key “lessons learned” from the CSUMB A.22.-08-003 are as follows and discussed in more detail below:

1. Planning for the design, property owner/landlord/tenant approvals and definitive agreement, cost-sharing, hiring of contractors, inspection and remediation of and construction and installation of 400+ individual building electrification projects along with simultaneous priority safety-related replacement of the pipeline facilities serving those buildings, took much longer than originally anticipated.

Contrary to the assumption that the project would require relatively simple approval by one party (CSUMB as landlord to the faculty and students occupying CSUMB-owned housing), it became clear later to both CSUMB and PG&E that a number of individual tenants in the individual 400+ units were not accepting changes in their unit gas service even though they were not the property owner and PG&E customer of record.

Even if the CSUMB tenants (faculty and students) had unanimously and rapidly consented to changes and termination of their gas service, the differing needs of individual consenting tenants means that the scheduling and management of actual in-building, behind-the-meter electrification work takes substantially longer compared to the scheduling of the to-the-meter replacement of gas mains and services outside the building.

The “lesson learned” is that PG&E and decarbonization project participants must plan for longer than expected project planning, negotiation with customers even if only a single landlord/property owner customer, inspection and construction of building electrification projects, and avoid projects that do not align with the priority schedule for safety-related pipeline replacement projects.

2. PG&E, interested parties and the Commission were unable to achieve a consensus and/or settlement of cost recovery, cost sharing and cost effectiveness issues related to the project on the expedited procedural schedule requested by PG&E in its CSUMB Application. Although PG&E requested an expedited schedule for Commission approval in its August, 2022 CSUMB project application, delays in PG&E reaching agreement with CSUMB on the precise scope of the project and a required definitive agreement, coupled with multiple rounds of discovery and testimony by PG&E and interested parties, meant that the opportunity for PG&E and interested parties to negotiate and reach a consensus and/or settlement of contested cost effectiveness, cost sharing and cost recovery issues was delayed for over two years after PG&E's initial application filing. This meant that a Commission decision based on briefing and the contested issues would likely have been delayed for four years after filing of the application, thereby conflicting with PG&E's obligation to replace the CSUMB pipeline facilities consistent with its priority for safety.

The "lesson learned" is that PG&E and interested parties should solicit, file for or support decarbonization projects requiring Commission approval based on a realistic schedule for Commission approval—including litigation and determination of contested issues associated with the proposed project—as well as the priority for safety-related pipeline repairs and replacement—that provides that all such project scheduling issues are resolved prior to the safety-related priority schedule for replacement or repair of the pipeline facilities proposed to be avoided by the project.

3. PG&E was too optimistic regarding the potential for reaching settlement and/or consensus with interested parties on contested issues. Such a settlement and/or consensus on

contested issues would have allowed PG&E to comply with its requested safety-related expedited schedule as well as manage other normal scheduling delays for approval and implementation of the project and replacement of the pipeline facilities avoided by the project.

The lesson learned is that PG&E, in setting and implementing a schedule for a safety-related or other schedule-dependent decarbonization project, should realistically assume potential litigation and other procedural issues in a Commission proceeding seeking approval of the project. PG&E should solicit and support decarbonization projects where the business project and safety-related schedule is based conservatively on participation, approval and decisions required not only by PG&E but also by interested parties and the Commission itself.

B. Indicated Shippers

Indicated Shippers actively engaged throughout this proceeding and submitted three rounds of testimony challenging PG&E's scope of work, revenue requirement analyses, cost-effectiveness analyses, and proposals for regulatory asset treatment, cost allocation and rate recovery. These fundamental yet unresolved issues provide the following key lessons that can inform future considerations of zonal electrification and similar decarbonization efforts.

1. Revenue Requirement Analysis

Indicated Shippers consistently maintained that PG&E's revenue requirement analyses of the planned gas pipeline replacement and proposed electrification alternative lacked transparency and failed to convey the long-term impact on gas ratepayers. Indicated Shippers' Witness Brian Collins noted that PG&E's proposal relied on short-term snapshots and cash flow metrics rather than presenting the full regulatory revenue requirement for each alternative over its lifecycle. His testimony emphasized that this omission is critical because the revenue requirement, not project cash flow, determines actual customer bills and affordability, and is necessary for an apples-to-apples comparison.

PG&E's initial analysis was for electrifying 620 campus housing units at CSU Monterey Bay at an estimated Present Value of Revenue Requirements (PVRR) of $16.7 million for the pipeline replacement and $17.7 million for the electrification project. However, Witness Collins' testimony identified several flaws in PG&E's PVRR analyses which suggested that the electrification project would have been more costly than the estimated $16.7 million, from the gas ratepayer perspective.

First, PG&E did not account for the lost gas revenues that it would not collect.

Electrification of the CSUMB housing units would eliminate those units' contribution to gas system fixed costs, shifting approximately $320,000 annually to remaining gas customers. This omission understated the true cost of electrification. Second, PG&E excluded corporate overhead and Administrative and General (A&G) costs from the electrification analysis, even though such costs were included for the pipeline replacement alternative. Third, PG&E's lifecycle comparison was incomplete; it presented only two years of revenue requirements for the gas pipeline replacement (2025–2026), rather than the full 35-year depreciable life of the pipeline, while amortizing electrification costs over 15 years. These omissions resulted in an analysis that understated the electrification project's true burden on remaining natural gas ratepayers and ultimately failed to provide a transparent or equitable comparison between the electric and gas alternatives.

PG&E's amended electrification proposal reduced the scope from 620 to 414 housing units and lowered the capital estimate to $11.27 million, but the same flaws persisted.

Compounding these issues, PG&E added asbestos remediation costs to its electrification project estimate late in the process. PG&E indicated that it was unable to conduct any destructive testing to determine the scope of necessary asbestos-related remediation work. Instead, PG&E estimated this line item using high-end historical remediation averages from the San Joaquin Valley Affordable Energy Pilot. This created an added layer of uncertainty surrounding the actual costs for the electrification project.

Beyond these omissions, Witness Collins' testimony asserted that the framework PG&E used to evaluate project economics was fundamentally misaligned with how rate impacts are actually experienced by PG&E's gas customers. He noted that PG&E relied on cash flow and Net Present Value (NPV) metrics, which do not reflect the timing and magnitude of zonal electrification project cost recovery in gas rates. Witness Collins explained that the appropriate measure is the regulatory revenue requirement over the life of each project, because this is what drives customer bills. Accordingly, a complete analysis should have compared the full revenue requirements for the electrification and pipeline replacement alternatives on a consistent, lifecycle basis.

Lesson Learned:

Future electrification proposals must present complete lifecycle revenue requirement analyses for all alternatives, covering full lifecycle costs, overheads, and lost revenues. Analyses should include contingencies for unexpected costs, like asbestos remediation, and be conducted from the perspective of affected utility ratepayers proposed to be burdened with the project costs.

2. Cost-effectiveness Analysis

PG&E's cost-effectiveness analysis purportedly addressed whether the electrification project is economically justified compared to the planned gas pipeline replacement work when all relevant costs and benefits are considered. PG&E's analysis concluded that electrification was favorable based on a benefit-cost ratio of 1.3 under its revised scope. However, Witness Collins explained that this ratio was derived from flawed assumptions and incomplete inputs.

Specifically, his testimony noted that PG&E expensed capital costs in year one rather than amortizing them over the project life, ignored appliance replacement costs beyond 15 years, excluded corporate overheads and gas regulator station rebuild/replacement costs, and failed to account for lost gas revenues. He further opined that PG&E relied on optimistic assumptions about behind-the-meter (BTM) appliance life and avoided gas costs without adequate support.

Moreover, Witness Collins underscored that PG&E's methodology focused on project cash flows rather than incorporating the full economic implications of lifecycle costs. He explained that a robust cost-effectiveness analysis should evaluate whether the project delivers net NPV benefits under realistic conditions, including sensitivity testing and contingency planning for late-stage discoveries such as asbestos remediation. PG&E's inclusion of asbestos costs, without verification, illustrates the risk of relying on uncertain estimates. Witness Collins' testimony demonstrated that, after correcting flaws in PG&E's analysis, the proposed electrification project was not cost-effective for gas ratepayers, yielding a benefit-cost ratio of less than 1.0.

Lesson Learned:

Cost-effectiveness evaluations must incorporate sensitivity testing, lifecycle costs, and system fixed costs, shifting approximately $320,000 annually to remaining gas customers. This omission understated the true cost of electrification. Second, PG&E excluded corporate overhead and Administrative and General (A&G) costs from the electrification analysis, even though such costs were included for the pipeline replacement alternative. Third, PG&E's lifecycle comparison was incomplete; it presented only two years of revenue requirements for the gas pipeline replacement (2025–2026), rather than the full 35-year depreciable life of the pipeline, while amortizing electrification costs over 15 years. These omissions resulted in an analysis that understated the electrification project's true burden on remaining natural gas ratepayers and ultimately failed to provide a transparent or equitable comparison between the electric and gas alternatives.

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Lesson Learned:

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Lesson Learned:

Cost-effectiveness evaluations must incorporate sensitivity testing, lifecycle costs, and contingencies for late-stage discoveries. Underlying assumptions must be documented and validated early in the process, and analyses must include all relevant lifecycle cost impacts to avoid misleading conclusions.

4. Regulatory Asset Treatment

Indicated Shippers opposed PG&E's proposal to treat BTM electrification costs as regulatory assets eligible for a rate of return. Because PG&E would not own or maintain these assets, capitalization would be inconsistent with Commission precedent and cost-causation principles and could result in uncertain taxation liability issues. Critically, capitalization would further increase costs for remaining gas customers while the corresponding benefits of electrification would accrue to the affected PG&E electric customers. Thus, allowing PG&E to earn a return on non-utility property would benefit shareholders while imposing unjustified costs on ratepayers, thereby exacerbating affordability concerns.

Lesson Learned:

The Commission should affirm its prohibition against regulatory asset treatment for BTM appliances that are not owned and operated by the utility. Future electrification proposals should consider alternative ratemaking approaches for customer-side investments that align with cost-causation and avoid imposing unjust and unreasonable costs on remaining natural gas customers.

5. Cost Recovery

Indicated Shippers strongly objected to PG&E's plan to recover the full cost of the electrification project through natural gas distribution rates. CSU Monterey Bay and its tenants would have been the sole beneficiaries of the electrification project, yet they were not required to contribute financially to the project. Indicated Shippers' testimony asserted that requiring gas ratepayers to fund an electrification project benefiting CSU Monterey Bay and its tenants violates cost-causation principles and raises equity concerns, particularly given the affordability challenges associated with the natural gas transition.

Notably, to mitigate the risk associated with the significant uncertainty surrounding PG&E's electrification project cost estimates, the parties stipulated to a cost cap equal to PG&E's final estimated electrification cost of $11.27 million, enforced through a one-way balancing account. While this provision would have helped to protect ratepayers from excessive cost overruns, it was only a half-measure as it did not resolve the fundamental issue with allocating electrification costs to natural gas ratepayers.

Lesson Learned:

Electrification project costs should be minimized first by the use of non-ratepayer funding sources, with remaining costs allocated to the customers for whom the costs are incurred. Cost caps and one-way balancing accounts should be implemented to protect those benefitting ratepayers from project cost overruns.

6. Procedural Issue: Admission of Confidential Data Responses

To support its position, the Indicated Shippers sought admission to the evidentiary record of certain confidential PG&E data responses that were directly relevant to PG&E's economic analyses. These data responses included Excel spreadsheets and workpapers supporting tables in PG&E's supplemental amended testimony. In lieu of evidentiary hearings, the Indicated Shippers and PG&E stipulated to the entry of these exhibits, which were marked as Exhibit IS-10 and Exhibit IS-10-C in the December 13, 2024 Motion for Admission of Exhibits into Evidence.

Concurrently, PG&E and the Indicated Shippers filed a Motion to File Under Seal requesting confidential treatment for Exhibit IS-10-C, citing PG&E's designation of the information as confidential.

On December 23, 2024, the Administrative Law Judge issued a ruling admitting most exhibits but denying admission of Exhibits IS-10 and IS-10-C, finding that the confidentiality request was not adequately supported under Commission rules. Indicated Shippers requested but were unable to obtain a declaration from PG&E substantiating the confidentiality claim. As a result, the record lacks detailed cost data that would have been directly relevant to evaluating PG&E's revenue requirement and cost-effectiveness analyses.

Lesson Learned:

Future proceedings should ensure that underlying data supporting economic analyses is admitted into the record, with clear confidentiality protocols and supporting declarations to facilitate transparency and informed decision-making.

C. TURN

PG&E identifies three lessons learned from A.22-08-003 in its draft Lessons Learned Report (draft report). TURN offers feedback on each below.

As an initial matter, TURN observes that PG&E's draft report largely focuses on operational execution issues such as scheduling delays, tenant coordination challenges, and the difficulty of reaching settlement - while insufficiently addressing the required policy, cost, and ratepayer impact dimensions of lessons learned. TURN's feedback below helps to address the topics missing from PG&E's draft report.

Lesson #1 ("longer than expected project timeline")

PG&E explains that the "lesson learned" is that "PG&E and decarbonization project participants must plan for longer than expected project planning, negotiation with customers even if only a single landlord/property owner customer, inspection and construction of building electrification projects, and avoid projects that do not align with the priority schedule for safety-related pipeline replacement projects."

TURN generally agrees with this lesson learned. To better illustrate the lesson learned, TURN recommends that the report include a high-level comparison between the original assumed design-build-construction timeline presented in PG&E's August 10, 2022 application and the actual or expected post-litigation and tenant-resolution timeline (prior to the cessation of efforts by PG&E).[1]

TURN also notes, however, that any potential problems with tenant acceptance were not apparent to parties in the proceeding outside of PG&E and CSU Monterey Bay. In its testimony submitted in this proceeding, PG&E stated that "although resident outreach and buy-in are essential, the decision to cease gas service can be made solely by CSU Monterey Bay. Without the need to obtain individual service termination contracts from 600 customers, the retrofit work can proceed with the certainty and expedience required to avoid pipeline replacement." (A.22-08-003, PG&E Amended Testimony, Dec. 19, 2022, p. 1-6, lines 9-13.) PG&E reiterated in Status Reports filed in October 2023 and June 2024 that negotiations for a final agreement were continuing, without any hint of problems with tenant acceptance.

For future projects, especially SB 1221 projects, TURN thus suggests that a corollary lesson learned is that other local entities should be involved in conversations with property owners and tenants, so as to promote acceptance by all affected parties. Furthermore, TURN generally agrees that electrification projects should avoid priority pipeline replacement projects. For this reason, in Rulemaking 24-09-012, TURN recommended focusing potential non-pipeline alternative projects in areas where gas replacement/repair projects are forecast to be necessary at least three to five years out, or even longer.

Lesson #2 (cost recovery, cost sharing, and cost effectiveness)

PG&E states that the inability to reach settlement reflected the difficulty of resolving contested issues on an expedited schedule. However, the draft report does not substantively describe what those contested issues were, why parties disagreed, or how those disagreements informed PG&E's final litigation position prior to seeking leave to withdraw the application.

TURN recommends that PG&E revise this section to explicitly document party positions and rationales regarding, at minimum: whether gas or electric ratepayers should bear electrification costs, how costs should be recovered (straight-line vs. accelerated recovery); the

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[1] PG&E notes that this information can be accessed in the record of A.22-08-003 available on the CPUC documents search website as referenced in the first paragraph of this "lessons learned" report.

appropriate CPUC-approved ratepayer impact and cost-effectiveness tests; methodological assumptions including discount rates (ranging from 0–10 percent), EUL time horizons (10–20 years), gas mains/services pipeline useful life, assumptions on panel upgrade needs/costs, and the appropriate comparison metrics between gas vs. electric alternatives (e.g. nominal benefit-cost ratios versus net present value of revenue requirements); the treatment and valuation of greenhouse gas benefits (including assumed $/ton social cost of carbon ranges); and, most importantly, party positions regarding capitalization and regulatory treatment of behind-the-meter (BTM) assets. These issues were central to the proceeding and the issues (including a set of appropriate data sources provided by PG&E / intervenors in support of their respective positions) should be transparently memorialized.[2]

Further, and consistent with Ordering Paragraph 3's requirement to address cost and ratepayer impacts, PG&E should also include a concise table summarizing contested cost inputs and ranges drawn from intervenor testimony and its own original August 10, 2022 application vs. amended December 19, 2022 application**,** with brief explanations for changes. This should include, at a minimum, Tables 2-2 and 2-3 of the original application (pp. 2-3 and 2-4, in constant 2026 dollars) with a summary of intervenor concerns regarding specific line items—such as construction labor, corporate overheads, cross-bore remediation, heat pump installation costs, remediation costs, and water heater assumptions—along with PG&E's final rebuttal positions.[3]

Having this information readily available in the Lessons Learned report will enhance the report's value for proponents and stakeholders of future decarbonization projects.

PG&E also concludes that "PG&E and interested parties should solicit, file for or support

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[2] PG&E notes that these documented comparisons can be reviewed in the record of A.22-08-003 accessible on the CPUC document search website as provided in the first paragraph of this "lessons learned" report.

[3] PG&E notes that this record information and the referenced tables can accessed in the record of A.22-08-003 on the CPUC document search website as provided in the first paragraph of this "lessons learned" report.

decarbonization projects requiring Commission approval based on a realistic schedule for Commission approval – including litigation and determination of contested issues associated with the proposed Project – as well as the priority for safety related pipeline repairs and replacement – that provides that all such Project scheduling issues are resolved prior to the safety-related priority schedule for replacement or repair of the pipeline facilities proposed to be avoided by the project."

As discussed extensively in TURN's comments submitted in R.24-09-012, TURN suggests that the lesson learned is that cost recovery issues should not be litigated separately for each and every potential proposed decarbonization project. Instead, the Commission should establish a uniform policy concerning cost recovery that provides proper incentives without unfairly burdening ratepayers. This issue has been squarely presented for Commission resolution in comments submitted in R.24-09-012 on December 3, 2025 and December 17, 2025.

Lesson #3 ("safety-related expedited schedule")

PG&E concludes that future schedule-dependent decarbonization projects, such as safety-related projects, should assume that parties will contest elements of the project, and that disputes will impact the schedule for Commission decision-making.

TURN agrees that disputes are likely to impact the schedule for Commission resolution of proposed decarbonization projects. But as noted by TURN in response to Lesson #2, some of those disputes, particularly cost recovery policy issues, should be resolved by the Commission through a uniform policy to avoid the need to litigate similar cost recovery issues for each potential decarbonization project.

Moreover, the Lessons Learned report should recognize that a key contributor to delay in A.22-08-003 was the late disclosure of foundational safety issues that necessitated abrupt withdrawal of this application. TURN recommends that the report explicitly state that, for safety-driven gas pipeline replacement projects, IOUs should provide core pipeline risk information (including, but not limited to, latest likelihood / consequence of failure data from DIMP, latest RAMP related relative risk ranking) and a time-based estimate of urgency for pipe replacement at the outset of decarbonization proceedings, rather than after multiple rounds of discovery and testimony.[4]

Including this information at the time of project proposal may save others from re-learning this lesson in the future.

TURN appreciates PG&E's collaboration in completing the Lessons Learned report as anticipated by the Commission in D.25-11-004.

[4] PG&E agrees generally with this conclusion for future zonal electrification projects, but disagrees that this information was not fully provided and available throughout the record of A.22-08-003.