



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

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Order Instituting Rulemaking to Establish
Policies, Processes, and Rules to Ensure
Safe and Reliable Gas Systems in California
and Perform Long-Term Gas System
Planning.

Rulemaking No. 24-09-012
(Issued October 4, 2024)

(U 39 G)

**OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY
(U 39 G) ON ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING
ADDITIONAL INFORMATION TO IMPLEMENT SENATE BILL 1221**

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Pursuant to the Administrative Law Judge’s Ruling (ALJ Ruling) issued March 17, 2026, requesting additional information to implement Senate Bill 1221 (SB 1221), Pacific Gas and Electric Company (PG&E) provides its opening comments in response to the specific questions included in the ALJ Ruling.

I. INTRODUCTION

There are three key principles that should inform the cost treatment for zonal decarbonization pilot projects under SB 1221: 1) projects should be cost-effective for customers, 2) project costs should be recovered over time to support customer affordability, and 3) utilities should earn the same rate of return on these costs if recovered over time as they would earn on an alternative gas investment where they finance and recover costs over time.

1) **SB 1221 zonal decarbonization pilot projects should be cost-effective.**¹ This means the electrification costs to ratepayers should be less than the avoided costs of the gas assets – a simple “avoided cost” principle and calculation. When the project costs – inclusive of behind-the-meter investments, decommissioning of gas assets, incentives, and any other program costs – are less than the costs of replacing and maintaining gas assets and the project meets other

¹ The use of the term “cost-effective” here refers only to the comparison of avoided gas investments to costs for zero-emission alternatives. It has no relation to, for example, cost-effectiveness tests as contemplated within the Distributed Energy Resources (DER) Customer Programs Proceeding (R.22-11-013).

requirements, the project should move forward.²

2) **Electrification costs should be recovered over time to support affordability instead of in the year incurred.** This is consistent with the way the Commission authorizes recovery of certain utility costs over time as “regulatory assets”³ for affordability or other public purposes. If all behind-the-meter costs hit rates in year 1, they will have a relatively large impact on near-term rates. When the costs are spread over time, they have a lower average rate impact in the near term which benefits customer affordability.

3) In addition to meeting cost-effectiveness and affordability criteria, **utilities should earn the same rate of return on electrification investments as they would earn on an alternative gas investment.** Utility costs recovered over time need to be financed by the utility, including the utility’s costs of debt and equity at its authorized cost of capital and capital structure. This ensures that the utility’s costs of electrification are on the same “level playing field” as the gas costs that are avoided by the electrification, while ensuring that the utility fully recovers its “just and reasonable” costs of the electrification, including financing costs. This is critical to enabling utilities to viably fund decarbonization projects that would otherwise not be considered cost-effective.

For these reasons and as discussed in more detail in Section II below, to make electrification investments more affordable to customers, the Commission should approve

² The electrification project must also meet all safety, reliability, scheduling and practical implementation criteria as well. See, e.g., PG&E’s “lessons learned” from its California State Monterey Bay application, filed January 26, 2026 in this proceeding at <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K270/596270217.PDF>.

³ The FERC Uniform System of Accounts, Definition 31 defines Regulatory Assets and Liabilities as assets and liabilities that result from rate actions of regulatory agencies. Regulatory assets and liabilities arise from specific revenues, expenses, gains, or losses that would have been included in net income determination in one period under the general requirements of the Uniform System of Accounts but for it being probable:

- A. that such items will be included in a different period(s) for purposes of developing the rates the utility is authorized to charge for its utility services; or
- B. in the case of regulatory liabilities, that refunds to customers, not provided for in other accounts, will be required.

See also D.20-04-004, Mobilehome Park Utility Conversion Program.

regulatory asset cost recovery for cost-effective electrification investments at the utilities' authorized cost of capital over a reasonable period of time.

II. PG&E RESPONSES TO COST RECOVERY QUESTIONS

1. Are Pub. Util. Code Section 663(b)(8) and Section 663(b)(9) in conflict? If not, why not? If so, in what way and how can they be harmonized?

PG&E Response: No, they are not in conflict: The appropriate rate of return for electrification regulatory assets financed by a gas utility voluntarily participating in an SB 1221 pilot program under PU Code 663(b)(9) should be the utility's rate of return under its authorized cost of capital.

PU Code 663(b)(8) does not modify PU Code 451.9(b)(1) enacted by SB 1221, because PU Code 451.9(b)(1) requires that the rates for the substitute electrification service under an SB 1221 pilot program must be just and reasonable. This includes all utility costs of service that are just and reasonable and financing costs the utility incurs on behalf of the customer at the utility's cost of capital. PU Code 663(b)(8) does not affect or repeal the Commission's authority to determine the just and reasonable rates for recovery of a gas or electric utility's reasonable costs of gas and electric service.

The rules of statutory construction require consideration of the "*plain meaning*" of Section 663(b)(8), and its statutory construction in combination with the rest of SB 1221. Section 663(b)(8) refers solely to utility "capital costs," which are defined in utility ratemaking as capitalized plant assets⁴ directly used and owned by a utility to provide utility service to

⁴ The FERC Code of Federal Regulations, Title 18, Subchapter C, Part 101, Uniform System of Accounts, Balance Sheet Chart of Accounts, defines Electric Plant in Service as the original cost of electric plant included in electric plant accounts 301 to 399, owned and used by the utility in its electric utility operations, and having an expectation of life in service of more than one year from the date of installation. Likewise, Chapter I, Subchapter F, Part 201 of the Uniform System of Account, Balance Sheet Cart of Accounts defines account 101, Gas plant in Service as gas plant, included in gas plant accounts 301 to 399, owned and used by the utility in its gas operations, and having an expectation of life in service of more than one year from date of installation.

Regulatory assets are categorized in the FERC CFR in both Parts 101 and 201 balance sheets as deferred debits in account 182.3 which is defined as follows: A. This account shall include the amounts of

customers. “Regulatory assets,” on the other hand, are a method for accounting for costs that are *not* “capital costs.” Rather, these are costs that are normally expensed but are being amortized in customers’ utility rates over periods subsequent to the utility’s incurrence of the costs, to meet a special regulatory goal or provide public policy benefits, such as reducing customer rates over time or promoting affordable rates. In other words, customers’ behind-the-meter electric appliances and other costs are not utility “plant assets” and therefore financing costs for those appliances are not capital costs. Seeking regulatory asset treatment to recover the costs of customer incentives over time rather than immediately to support customer affordability associated with building electrification requires the costs to be *treated as regulatory assets* and amortized over a specified period, and is not asking that capital dollars be spent on physical building electrification assets. Therefore, regulatory asset treatment for electrification costs is not in conflict with Section 663(b)(8) of SB 1221, because it does not ask for *capital costs* to be afforded a rate of return, but rather *costs* to be afforded a rate of return as regulatory assets, because the costs they avoid are incurred for a public benefit or for achieving a public policy goal.

This distinction is supported by an “*in pari materia*” review of other provisions of SB 1221 including the statutory requirement in PU Code 451.9(b)(1), which make clear that SB 1221 does *not* amend or modify the Commission’s authority to allow and specify the methodology for a utility to recover all reasonable costs it incurs to provide gas and electric service. This authority includes the costs of SB 1221 pilot projects that are not traditional capital plant costs but instead are regulatory asset costs amortized over time to achieve the fundamental

regulatory-created assets, not includible in other accounts, resulting from the ratemaking actions of regulatory agencies. (*See* Definition No. 31.)

B. The amounts included in this account are to be established by those charges which would have been included in net income, or accumulated other comprehensive income, determinations in the current period under the general requirements of the Uniform System of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing rates that the utility is authorized to charge for its utility services.

regulatory purposes of SB 1221. The purposes include reduced costs to customers and testing and piloting different methods for implementing building electrification and decarbonization.

This statutory construction also is consistent with the intent of SB 1221 that electric and gas utilities should recover all reasonable costs of SB 1221 program costs.⁵ The regulatory asset treatment at the utility's authorized cost of capital is the most affordable way to provide a reasonable incentive to customers to electrify, including the costs of behind-the-meter electric appliances, at the utility's authorized cost of capital incurred by the utility to provide and recover the costs of financing those electrification costs over a reasonable amortization period at a reasonable cost to both the participating customers and all customers. This applies whether the costs are amortized and financed by only gas customers, only electric customers, or combined gas and electric customers.

For all these reasons—factual, practical, legal and public policy—the Commission should reconcile the statutory construction of Public Utilities Code Sections 451.9(b)(1), 663(b)(8), and 663(b)(9), and construe SB 1221 to authorize full regulatory asset cost recovery of the behind-the-meter costs of SB 1221 pilot decarbonization projects, including a return on the regulatory asset at the utility's authorized cost of capital used to finance the projects.

2. Should the Commission allow rate recovery of BTM zero-emission alternative (ZEA) implementation costs incurred by gas utilities (i.e., the utility may recover approved program costs from gas ratepayers)? Why or why not?

PG&E Response: Yes, see response to Question 1, above.

3. If the Commission authorizes utilities to recover approved BTM costs, should the Commission authorize expense treatment, where costs are recovered in rates in the year they are incurred? Why or why not?

PG&E Response: No, the Commission should not require utilities to expense electrification costs in rates, because passing through immediate expenses in a single year of customers' behind-the-meter, remediation, and other upgrade costs to replace gas appliances

⁵ Senate Bill 1221, Stats. 2024, ch. 602, Section 1.

with new electric appliances is less affordable to customers. Such treatment would limit the utilities' ability to implement affordable and cost-effective decarbonization and electrification projects at a scale broad enough to support California's carbon neutrality goals.

4. If the Commission authorizes utilities to recover BTM costs, should the Commission authorize regulatory asset treatment? Why or why not?

PG&E Response: Yes, the Commission should approve regulatory asset treatment at the utility's authorized cost of capital, consistent with cost of service ratemaking which promotes affordability for customers for building electrification investments. This is an affordable path to provide financial incentives to participating customers to replace their gas service with electrification. This treatment improves affordability for all ratepayers, because the costs are spread over a longer time period instead of hitting customer bills immediately or in a single year.

5. If you recommend regulatory asset treatment, address the following questions:
 - a. Which amortization period should the Commission adopt: five years, 10 years, 15 years, 20 years, or something else? Provide justification.

PG&E Response: Based on further review, a balanced amortization period of 10 years helps limit the cost recovery period and reduce the overall present value of revenue requirements that customers bear over that time period. Other costs, including any required in-front-of-the-meter and related electric distribution costs resulting from program adoption, should be recovered consistent with existing cost of service ratemaking and allocation methodologies for cost of service ratemaking in General Rate Cases.

- b. What depreciation schedule(s) should apply to BTM costs if the Commission were to grant regulatory asset treatment? Should there be straight-line depreciation for an amortization period (e.g., 5 percent annual depreciation over a 20-year amortization period)? Should there be an accelerated depreciation schedule? Should a single depreciation schedule be applied to all BTM assets? Provide justification.

PG&E Response: As BTM costs are not treated as plant assets, cost recovery should not be based on a plant depreciation rate. These regulatory assets should be amortized straight-line over the time period authorized by the Commission. The depreciation and amortization methodology applicable to the utility's capitalized plant and regulatory assets should be consistent with the methodology approved and authorized by the Commission in the utility's currently applicable General Rate Case and consistent with the Uniform System of Accounts for regulatory assets, subject to providing recovery over a reasonable period of time.

- c. Considering your responses to Questions 5(a) and 5(b), what would be the appropriate compensation for the gas corporation on the amortized expenditures and why? If the Commission were to grant regulatory asset treatment for BTM expenditures, what rate of return should be authorized? What clarifications would be necessary, if any, regarding allocation of BTM expenses to long-term debt? Consider the following three options and identify the most appropriate option and why:
- **Option 1:** BTM expenditures are recorded as pilot program expenses and amortized over a period of time, with gas corporations receiving a carrying cost equal to their authorized cost of debt.
 - **Option 2:** BTM expenditures are treated as regulatory assets that are afforded an adjusted rate of return that would differ from the authorized rate of return for capital investments to account for the fact that the utility would not own or maintain any BTM assets as capital assets. Those BTM expenditures would (1) be amortized over a shorter period of time compared to the gas capital asset (see Question 5(a) above), (2) would depreciate faster than the gas capital asset (as determined by responses to Question 5(b) above), and (3) would receive a lower rate of return set at the midpoint value of the IOU's cost of long-term debt and its prevailing authorized rate of return for capital expenses. This would result in a BTM expenditure rate of return of 6.325% for PG&E, 6.27% for SoCalGas, and 6.00% for SDG&E, as compared to their capital asset rates of return of 7.61% for PG&E, 7.52% for SoCalGas and 7.41% for SDG&E, as approved in D.25-12-043.
 - **Option 3:** BTM expenditures are recorded as pilot program expenses and amortized over a period of time, with gas

corporations receiving a carrying cost equal to their authorized cost of debt, as with Option 1 above. In addition, the gas corporation is eligible for a one-time shareholder incentive tied to program outcomes. Gas utility shareholders and remaining gas customers share the net cost savings from successful pilot projects. The following example illustrates one way such an incentive could be structured. Parties may wish to propose alternative incentive structures, which must be tied to program outcomes and can be implemented with data collected from pilot implementation.

PG&E Response: The utility’s cost recovery for its regulatory assets should comply with the Commission’s adopted and traditional cost of service ratemaking for capital and regulatory assets: The regulatory assets should be amortized in utility rates over a reasonable period with return at the utility’s authorized cost of capital to ensure full recovery of the utility’s financing costs. Regulatory commissions have long recognized that utilities must be afforded a fair opportunity to earn an authorized return on invested capital and regulatory assets in order to attract capital on reasonable terms and finance infrastructure and other costs necessary to meet public service obligations.⁶ When PG&E commits funding to long-lived capital or regulatory assets, it does so in advance of recovery and assumes the financing, construction, and operational risks. It is well established that under this business and regulatory model, utilities should be provided with a reasonable opportunity to recover their costs, and when it is over multiple years, that includes a return of and on the assets at their authorized cost of capital.

None of the three options listed in the questions, including the “Option 3 Example,” complies with cost of service ratemaking for capital and regulatory assets. None of the three options provides for full recovery of the utility’s reasonable costs of capital and financing costs associated with the regulatory asset. Moreover, under cost of service ratemaking, reasonable utility costs of service recovered over time, such as over a reasonable period of the behind-the-meter electric appliances and other costs financed by the utility under a decarbonization program such as SB 1221, should include the utility’s authorized cost of capital regardless of whether the

⁶ See, e.g. CPUC description of cost of capital ratemaking at CPUC website [Cost of Capital](#).

appliances are “owned” by the utility.

III. CONCLUSION

For the reasons stated above, the Commission should authorize utilities that voluntarily participate in SB 1221 neighborhood decarbonization programs to fully recover the costs of their investments in electrification facilities, including behind-the-meter electric appliances, as regulatory assets amortized in rates over a reasonable period of time for affordability, including a return of and on the regulatory assets at the utilities’ current authorized costs of capital.

Respectfully Submitted,

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