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 24-09-012 (Issued October 4, 2024)

SIERRA CLUB AND NATURAL RESOURCES DEFENSE COUNCIL OPENING COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING ADDITIONAL INFORMATION TO IMPLEMENT SENATE BILL 1221

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Dated: March 27, 2026

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Pursuant to the March 17, 2026, Administrative Law Judge's Ruling Requesting Additional Information to Implement Senate Bill 1221 ("ALJ Ruling"),[1] Sierra Club and the Natural Resources Defense Council ("NRDC") timely submit the following Opening Comments.

I. RESPONSE TO QUESTIONS IN ALJ RULING

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?

Public Utilities Code Section 663(b)(8) prohibits gas utilities from recovering the behind-the-meter ("BTM") costs of zero-emission alternatives ("ZEAs") to new capital investments in the gas system "as capital costs that are afforded a rate of return" while Section (b)(9) directs the Commission to set the "appropriate rate of return and recovery period that a gas corporation is eligible to receive for its costs to implement a zero-emission alternative."[2] These Sections can be harmonized by treating BTM costs of ZEAs as regulatory assets that have a cost-recovery period that balances near- and long-term savings for gas ratepayers. As discussed in response to Question 4 and in Sierra Club and NRDC Opening Comments on Second Amended Assigned Commissioner Scoping Memo, regulatory asset treatment is distinct from allowing the utilities to recover BTM costs as typical capital expenditures for utility-owned gas plant in their General Rate Cases ("GRCs").[3] To the extent the Commission is inclined to further distinguish the cost

[1] R.24-09-012, Administrative Law Judge's Ruling Requesting Additional Information to Implement Senate Bill 1221 (Mar. 17, 2026), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M602/K365/602365926.PDF.
[2] Cal. Pub. Util. Code § 664(b)(8), (9).
[3] R.24-09-012, Sierra Club and NRDC Opening Comments on Second Amended Assigned Commissioner Scoping Memo and Ruling Requesting Comment on Pilot Program at 20-22 (Dec. 3, 2025), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M589/K800/589800493.PDF.

recovery provisions of Sections (b)(8) and (9), it can adopt a rate of return for the costs of ZEAs that differs from the rate of return for capital investments, i.e. the utilities' Weighted Average Cost of Capital ("WACC").

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?

Yes. Under Senate Bill ("SB") 1221, the Commission must establish a "requirement that gas corporations recover costs related to the pilot projects that are deemed just and reasonable."[4] Accordingly, the Commission is required by statute to ensure gas corporations recover reasonable costs related to pilot projects. As BTM ZEA implementation costs are a key driver of pilot project costs, they must also be eligible for rate recovery.

In addition, gas corporations should recover BTM ZEA implementation costs from gas ratepayers. Allocating Non-Pipeline Alternative ("NPA") costs to gas customers best aligns with cost causation principles because the gas investments that NPAs are designed to replace are driven by gas system needs, not by electric customers. In addition, because NPAs avoid long-term capital investments in the gas system that would otherwise occur, gas customers are their primary beneficiaries. Moreover, SB 1221 requires the Commission to determine the "appropriate rate of return and recovery period that a *gas corporation* is eligible to receive for its costs to implement a zero-emission alternative."[5] Had the Legislature intended electric utilities to pay BTM pilot project costs, SB 1221 would have explicitly identified electric corporations as the entities assuming and recovering costs.

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?

No. Authorizing expense treatment would strongly disincentivize successful pilot project execution and create significant near-term bill impacts by recovering all costs the year they are incurred. If the gas utility did not implement a non-pipeline alternative, it would be replacing a

[4] Cal. Pub. Util. Code § 663(b)(8).
[5] Cal. Pub. Util. Code § 663(b)(9) (emphasis added).

gas pipeline and gaining a profit off that investment for more than 50 years.[6] Treating the costs of ZEAs as expenses that do not generate any profit for utilities significantly disincentives their deployment and the corresponding climate, public health, equity and ratepayer benefits that would otherwise be realized. Because ZEAs further California's climate and air quality objectives and new investment in fossil fuel infrastructure perpetuates reliance on polluting fuels, the Commission should provide a similar financial incentive for gas corporations to execute ZEAs as they do for new gas infrastructure projects.

In addition, classifying the costs of NPA deployment as operational costs that are recovered the year they are incurred has significant near-term bill impacts compared to spreading those costs over time. To illustrate the difference, Table 1 below shows the lifetime ratepayer savings and Year 1 bill impacts of recovering $1 million in NPA costs as operational expenses recovered over one year or as regulatory assets over 10 or 15 years. The bill impacts presented below are compared against the default of capitalizing $1 million in service line replacement costs over 55 years that would occur were pipeline replacement to proceed. The table presents lifetime gas revenue requirement savings of the NPA investment in both nominal dollars and net-present value ("NPV"), and it presents the total Year 1 bill impact of the NPA investment on non-participating gas customers.[7]

Table 1: Comparison of NPA Revenue Requirement and Bill Impacts Across Cost Recovery Options[8]

Cost Recovery Method	Lifetime Cost Savings Compared	Lifetime Cost Savings Compared to Gas	Year 1 Bill Impact, Non-Participating Gas Customer

[6] For example, in the case of PG&E, gas distribution assets are depreciated over 55-60 years based on GRC 2023 authorized depreciation parameters. *See* A.25-05-009, PG&E Response to Data Request Sierra Club-PG&E-01, Q.19 (June 25, 2025), available at Attachments to Sierra Club and NRDC Testimony in PG&E General Rate Case, at pdf page 20 (June 25, 2025), https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2505009/8951/599037496.pdf.

[7] The NPV calculation assumes a customer-perspective discount rate of 5 percent.

[8] Results were generated using the NRDC NPA Cost Analysis Tool, which calculates the Net-Present Value Revenue Requirement (NPV RR) impact of an inputted gas utility investment and calculates Year-1 bill impacts based on core customer gas throughput. The calculation was conducted using PG&E-specific assumptions and applies a customer-perspective real discount rate of 5 percent. The NRDC NPA Cost Analysis Tool is provided as Attachment 6 of the Prepared Testimony of Matthew Vespa and Danielle Velez in the 2027 PG&E General Rate Case. Full documentation of the scenario inputs and outputs are provided on the "Cost Recovery Comparison" tab of that spreadsheet. Methodology documentation for the NPA Cost Analysis Tool is provided as Attach. 5. The attachments are available at Attachments to Sierra Club and NRDC Testimony in PG&E General Rate Case, at pdf page 20 (June 25, 2025), https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2505009/8951/599037496.pdf.

	to Gas Replacement (Nominal Dollars)	Replacement (Net-Present Value)	
All NPA Costs Expensed in Year 1	$2.7 million	$313,660	+ 12.67 cents
NPA Regulatory Asset Treatment, 10-Year Depreciation	$2.3 million	$203,042	+ 1.01 cents
NPA Regulatory Asset Treatment, 15-Year Depreciation	$2.1 million	$158,833	+ 0.58 cents

Paying the entirety of these costs in Year 1 would also result in more than a 12-fold increase in Year 1 bill impacts compared to amortization over 10 years. While treating these costs as an expense would have the lowest lifetime cost, regulatory asset treatment over a 10-year cost recovery period would still yield substantial ratepayer savings compared to the approximately 55-year return for a new gas distribution line. The impacts presented in the table above would only scale proportionately with greater NPA investment. Importantly, were gas corporations to receive the same rate of return for ZEA costs as for pipeline investments, lifetime ratepayer savings would still be substantial due to their far shorter cost recovery period than traditional pipeline investments.

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

The Commission should authorize regulatory asset treatment of BTM costs. This treatment is distinct from allowing the utilities to recover BTM costs as typical capital expenditures for utility-owned gas plant in their GRCs, which SB 1221 prohibits. Rather, it resembles the situations considered in the Commission's mobile home park utility conversion ("MHP Program"), which also allowed regulatory asset treatment for BTM, customer-owned equipment. In D.14-03-021, the Commission assigned regulatory asset treatment to BTM costs for voluntary conversions of mobile home parks from master meters to direct utility service.[9] The Commission found that "to the meter" costs should be rate based by the utilities in their GRCs because in-front-of-meter ("IFOM") investments "will result in used and useful additions

[9] D.14-03-021, *Decision on Issues Concerning Voluntary Conversion of Electric and Natural Gas Master-Metered Service at Mobilehome Parks and Manufactured Housing Communities to Direct Service by Electric and/or Natural Gas Corporations*, at 73–74, 77 (Conclusions of Law #16 & Ordering Paragraph #8) (Mar. 14, 2014), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K008/89008491.PDF.

to utility plant," but that "'beyond the meter' construction and its associated costs are different."[10] Because BTM investments were inherently necessary to achieve the goals of the program and thus provide ratepayers value from the program, the Commission found that those costs "should be treated as a regulatory asset" and "amortized over ten years at the rate equivalent to the utility's then-current authorized return on rate base."[11] The Commission renewed that cost recovery method for the next phase of the MHP Program in D.20-04-004.[12] Like the MHP Program, BTM investments for SB 1221 pilots are fundamental to achieving program goals.[13] The Commission should treat BTM costs of SB 1221 pilots similarly given the significant ratepayer and societal benefits of ZEAs and because the counterfactual to ZEA execution is a gas infrastructure replacement project that would be fully capitalized over a much longer cost-recovery period.

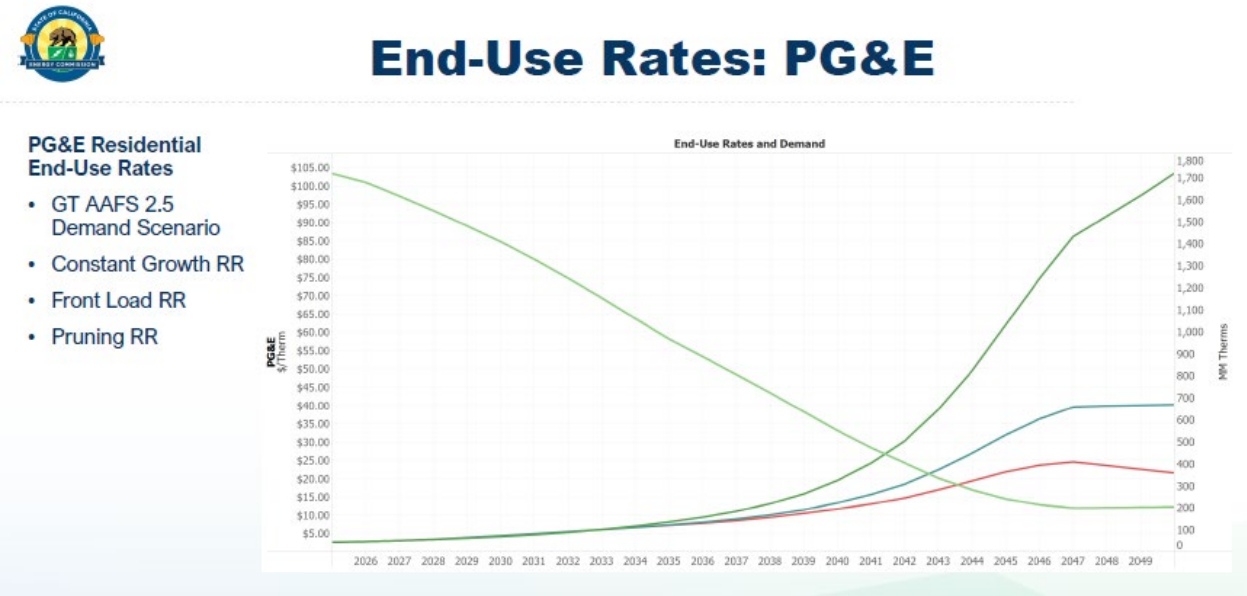
5. If you recommend regulatory asset treatment, address the following questions:

a) Which amortization period should the Commission adopt: five years, 10 years, 15 years, 20 years, or something else? Provide justification.

A 10-year amortization period best addresses the affordability and equity impacts from the gas transition. As shown in Table 1 above in response to Question 3, a 10-year cost-recovery period also reduces total project costs because the investment is paid off more quickly without creating significantly increased Year 1 bill impacts compared to a 15-year cost-recovery period. In addition, for projects implemented in 2030, a 10-year cost recovery period means project costs are fully paid off by 2040 as opposed to 2045 under a 15-year cost recovery period or 2050 under a 20-year cost recovery period. The California Energy Commission ("CEC") has begun to model end-use gas rates under various gas demand and gas system investment scenarios.[14] Gas

[10] *Id.* at 50.
[11] *Id*. at 50, 69–70 (Finding of Fact #36).
[12] D.20-04-004, *Decision Evaluating the Mobilehome Park Pilot and Establishing a Mobilehome Park Utility Conversion Program*, at 123, 127 (Apr. 24, 2020), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M334/K606/334606886.PDF.
[13] *See, e.g.* SB 1221 Sec. 1(a)(6) ("Cost-effective, zero-emission alternatives to pipeline replacement projects both reduce gas system costs and further California's efforts to reduce greenhouse gas emissions and improve air quality.").
[14] *See* CEC*, IEPR Commissioner Workshop on Gas Price Outlook (Fossil Gas, Formerly Known as Natural Gas)*, https://www.energy.ca.gov/event/workshop/2025-06/iepr-commissioner-workshop-gas-price-outlook-fossil-gas-formerly-known (last visited Feb. 23, 2026).

rates significantly escalate after 2040 under scenarios of gas demand decline coupled with continued business-as-usual investments in the gas system. For example, the CEC estimated PG&E residential gas transportation rates would increase close to fifty-fold by 2050, from $2.14/therm in 2025 to $102.76/therm in 2050, assuming continued business-as-usual investments in the gas system and declines in gas demand that would occur where buildings are electrified at a significantly slower pace than under the CARB Scoping Plan.[15]



As shown in the graph above, scenarios where there was a near-term increase in the revenue requirement compared to historic levels followed by minimal growth (a "Front Load" scenario) or an increase followed by annual reductions in the revenue requirement (a "Pruning" scenario)

[15] CEC, Docket No. 25-IEPR-03, TN #264063, 2025 IEPR End-Use Rate Results for California Utilities, PG&E Res Tab, Cells 80G, 105G (June 5, 2025), https://efiling.energy.ca.gov/GetDocument.aspx?tn=264063&DocumentContentId=100747; *see also* CEC, Docket No. 25-IEPR-03, TN #264052, Gas End-Use Rates: Understanding Long-Term Trends in Gas End-Use Rates, at Slide 31 (June 5, 2025), https://efiling.energy.ca.gov/GetDocument.aspx?tn=264052&DocumentContentId=100744. Assumptions for gas demand reductions under the Gradual Transformation (AAFS 2.5) Forecast and comparisons to reductions under the Scoping Plan are available at CEC, Docket No. 25-IEPR-03, TN #24046, 2023 IEPR Additional Achievable Fuel Substitution Scenarios, at Slide 6–7 (June 5, 2025), https://efiling.energy.ca.gov/GetDocument.aspx?tn=264046&DocumentContentId=100716.

resulted in significantly lower rate impacts in outer years.[16] By paying off these investments faster, a 10-year cost recovery period is better aligned with a Front Load scenario and avoids contributing to rate burdens in outer years when gas throughput is projected to be significantly lower than it is today.

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.

As discussed above, gas rates are projected to significantly increase after 2040 under a scenario that assumes continued business-as-usual investments in the gas system coupled with continued declines in gas demand. While straight-line depreciation may be appropriate for a 10-year cost recovery period, the Commission should consider faster-than-linear depreciation if it adopts a longer cost recovery period. This will help minimize risk of rate impacts in outer years for customers remaining on the gas system.

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:

(1) 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

[16] The CEC revenue requirement assumptions for each scenario are in the RR Growth Rate Tab at CEC, Docket No. 25-IEPR-03, TN #264063, 2025 IEPR End-Use Rate Results for California Utilities (June 5, 2025), https://efiling.energy.ca.gov/GetDocument.aspx?tn=264063&DocumentContentId=100747. In the graph, the light green descending line is gas demand under the CEC's Gas Transition ("GT") AAFS 2.5 Demand Scenario. The dark green line shows escalating gas costs under a scenario of continued revenue required increases and the blue and green lines show gas costs where the revenue requirement if front loaded or there is significant pruning of gas system.

cost of debt.

(2) 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….

(3) 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....

Utilities' compensation for BTM expenditures should balance customer savings with providing sufficient incentives for utilities to pursue ZEAs rather than gas infrastructure investments. While we support the concept of the incentive mechanism identified in Option 3 because it aims to balance these objectives by sharing the cost savings of successful programs between customers and shareholders, it may be difficult to ensure that this new approach alone will provide the certainty and incentives needed for utilities to pursue ZEAs prior to the July 1st statutory deadline to establish the pilot program.[17] Accordingly, we propose a combination of Option 2 and Option 3, which would both amortize BTM costs over 10 years at a rate of return between the cost of long-term debt and the WACC, and provide the performance-based incentive proposed in Option 3. Alternatively, the Commission could authorize recovery of BTM costs through a regulatory asset amortized over 10 years consistent with Public Utilities Code Section

[17] Cal. Pub. Util. Code § 663(a).

663(b)(8), as discussed in our comments on the Assigned Commissioner's Scoping Memo.[18] We believe either of these approaches may be appropriate for the ZEA pilots in this proceeding, and we may refine our specific recommendations in reply comments based on other commenters' input.

We do not recommend Option 1 because it does not adequately incentivize utilities to pursue ZEA pilots. At this early stage of ZEA implementation, the Commission's top priority should be initiating as many ZEA pilots as quickly as possible so that utilities, the Commission, and stakeholders can begin applying lessons learned from the pilots. The Commission should promote robust utility engagement in the pilot program by ensuring that compensation for gas corporations for BTM expenditures is similar to compensation the gas corporation would otherwise realize from new long-term capital investments in fossil fuel infrastructure. Failing to afford BTM costs of pilot projects a similar return as pipeline replacement disincentivizes their execution and the corresponding climate, public health, equity and ratepayer benefits that would otherwise be realized as well as critical learnings from successful NPA execution. In future proceedings when ZEA implementation becomes more routinized and refined through lessons learned in early pilots, the Commission should reevaluate cost recovery. For these reasons, the Commission should not pursue Option 1. Only awarding a return on debt for BTM expenditures will chill deployment of SB 1221 pilot projects due to the lack of return as compared to business-as-usual pipeline investments.

While the incentive mechanism proposed in Option 3 holds significant promise for balancing customer savings with utility incentives to pursue ZEAs, it may be premature to select this as the only means by which a gas utility obtains a return on BTM expenses at this early stage. Accordingly, we recommend that the Commission either authorize utilities to earn the WACC rate of return on ZEA pilots, or adopt a hybrid approach that combines Options 2 and 3. This approach would be similar to, but stricter than the approach taken in New York. In New York, NPA implementation costs are treated as regulatory assets with a full rate of return over a 20-year cost-recovery period along with an incentive mechanism whereby utility "shareholders

[18] R.24-09-012, Sierra Club and NRDC Opening Comments on Second Amended Assigned Commissioner Scoping Memo and Ruling Requesting Comment on Pilot Program at 20-22 (Dec. 3, 2025), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M589/K800/589800493.PDF.

would retain a 30 percent share of initial net benefits as determined by as societal cost test."[19] Here, the Commission would adopt a lower rate of return under Option 2 coupled with an incentive mechanism as proposed under Option 3. This would provide certainty that utilities will earn a reasonable rate of return while allowing for experimentation with a performance-based incentive approach. It could also give the Commission some flexibility to iterate and refine the incentive mechanism as it applies in different ZEA pilots while ensuring utilities recover a base-level rate of return. Given the small number of pilots permitted under SB 1221, ratepayer impacts would be minimal even if returns exceeded what the utility would otherwise have obtained under a return equal to the WACC. Whether the Commission authorizes recovery at the WACC rate or adopts a hybrid of Options 2 and 3, we recommend that the Commission direct utilities to include in the ZEA pilot reports under Public Utility Code § 664 information about the utility earnings and rate impacts that would result from the other cost recovery option (i.e., if the Commission authorizes WACC recovery, utilities would report what they would have earned through the incentive mechanism, and the Commission would provide any additional information needed to calculate the expected incentive—such as formulas for the normalized metrics for main and service line retirements and customer conversions—before the ZEA pilot reports are due). Insights and recommendations on improving the effectiveness of a performance-based approach could then be included in SB 1221's required reporting of pilot project implementation to inform future NPA policy.[20]

With regard to alternative incentives structures, the proposal in the ALJ Ruling is tied to cost savings with a multiplier that does not exceed 1 based on multiple factors that include metrics for customer conversions and decommissioned miles of main and service lines. While these factors reflect important potential benefits of ZEA pilots, a given pilot may be successful without scoring highly on each factor and metric. If the Commission pursues a performance incentive, it should consider alternate approaches that allow pilots to focus on some but not all metrics of success, with one that focuses exclusively on cost savings (ideally using a societal cost test to capture the pilots' decarbonization benefits and other societal benefits), and another that

[19] *See* State of New York Pub. Serv. Comm'n, *Order Approving Non-Pipes Alternative Project Amortization Period and Shareholder Incentive for Specified Projects,* Case 19-G-0066 at 8–9, 31 (June 2022), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={6949E2AD-0BFD-41A0-809D-1D34BF691FC5}.
[20] Cal. Pub. Util. Code § 664.

prioritizes the number of customers reached, with a multiplier for customers in disadvantaged communities ("DACs"). Projects serving larger numbers of customers, such as those that may require electrification of a multi-family building, may not result in large cost savings but may further equity and decarbonization objectives. Having two different approaches available to utilities would allow for a greater diversity in pilot projects and achievement of multiple program objectives. If the Commission makes multiple options available, we recommend that it direct utilities to include information about the utility earnings and rate impacts that would result from any available cost recovery options that they did not select in their ZEA pilot reports under Public Utility Code § 664.

II. CONCLUSION

Sierra Club and NRDC appreciate the opportunity to provide opening comments on the ALJ Ruling.

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Respectfully submitted,

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