

Docket No.: A.25-05-009

Exhibit No.: SC/NRDC-01

Date: February 13, 2026

Witnesses: Matthew Vespa
Danielle Velez

**PREPARED DIRECT TESTIMONY OF MATTHEW VESPA AND DANIELLE VELEZ
ON BEHALF OF SIERRA CLUB AND NATURAL RESOURCES DEFENSE COUNCIL
ON THE APPLICATION OF PACIFIC GAS & ELECTRIC FOR AUTHORITY,
AMONG OTHER THINGS, TO INCREASE RATES AND CHARGES FOR ELECTRIC
AND GAS SERVICE EFFECTIVE ON JANUARY 1, 2027**

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1 **I. INTRODUCTION**

2 This testimony is submitted on behalf of Sierra Club and the Natural Resources Defense
3 Council (“NRDC”) in A.25-05-009, the Application of Pacific Gas & Electric Company
4 (“PG&E”) For Authority, Among Other Things, to Update Its Gas Revenue Requirement
5 and Base Rates Effective on January 1, 2027 (“PG&E GRC Application”). Sierra Club
6 and NRDC’s joint testimony is limited to PG&E’s Gas Operations request, and
7 specifically the adequacy of its proposals to shrink the size of its gas system through
8 deployment of non-pipeline alternatives (“NPAs”) to new long-term capital investments
9 in the gas system. In this testimony, Sierra Club and NRDC propose modifications to
10 PG&E’s Alternate Energy Program (“AEP”) and recommend the California Public
11 Utilities Commission (“Commission”) require PG&E to implement an additional and
12 complementary Service Line NPA program that would offer a standardized voluntary
13 monetary incentive for full home electrification in lieu of gas distribution service line
14 replacement.

15 The witnesses sponsoring this testimony are Matthew Vespa, Senior Attorney at
16 Earthjustice, and Danielle Velez, Equitable Gas Transition Lead for NRDC. Mr. Vespa
17 has practiced before the Commission for the past fifteen years, is a lecturer on Renewable
18 Energy Law and Policy at Berkeley Law, and has provided testimony in several
19 Commission proceedings, including A.25-07-001, Application of SoCalGas, on Behalf of
20 its Customers, for Approval of Gas Line Extension Allowances; R.20-08-020, the Order
21 Instituting Rulemaking to Revisit Net Energy Metering Tariffs; and A.22-05-015,
22 SoCalGas’ 2024 General Rate Case (“GRC”) Application. Ms. Velez is NRDC’s lead
23 expert on gas utility system decarbonization policies and has represented NRDC in more
24 than twenty-five regulatory proceedings across the West and Midwest. The witnesses’
25 qualifications and resumes are included at the end of this testimony as Attachment 1. The
26 individual sponsoring a particular section of testimony is indicated at the end of each
27 heading or question.

28 **II. SUMMARY OF RECOMMENDATIONS (VESPA/VELEZ)**

29 In opening remarks at the Prehearing Conference for PG&E’s GRC Application,
30 Assigned Commissioner John Reynolds recognized fuel switching as an outcome-focused
31 priority for this proceeding, with consideration of the “right level of gas system pruning,
32 if any, over this GRC period.”¹ PG&E’s GRC Application does not meet the right level

¹ Reporters’ Transcript, Prehearing Conference, July 3, 2025, Vol.1 at 11:25-12:3, 13:11-12
(Commissioner J. Reynolds),
<https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M572/K574/572574471.PDF>.

1 of gas system pruning. By its own admission, PG&E is not proposing “any projects that
2 would start to significantly shrink the size of gas system.”² While PG&E is requesting to
3 continue AEP, it has averaged less than a dozen meter conversions over the past four
4 years.³ Even if PG&E is able to successfully scale up AEP in this GRC cycle to achieve
5 its new goal of 180 annual meter conversions, PG&E’s GRC Application leaves critical
6 low-hanging opportunities to prune the gas system on the table.

7 To meet the right level of gas system pruning over this GRC period, the Commission
8 should require PG&E to augment AEP with a Service Line NPA Program that offers
9 standardized voluntary incentives to customers facing a service line replacement to fully
10 electrify their home and disconnect from the gas system instead. Between 2022 and
11 2024, PG&E replaced an average of over 15,000 service lines annually, the vast majority
12 of which connected to a single residential customer meter.⁴ This makes service line
13 replacements the least complicated type of NPA to execute and provides the opportunity
14 to offer NPAs to households across PG&E’s service territory. Service Line NPA
15 programs are already being implemented by utilities such as Consolidated Edison (“Con
16 Edison”) in New York to complement other NPA programs that focus on larger, more
17 complex projects that require individualized assessments and coordination among
18 multiple property owners.

19 By requiring PG&E to implement a Service Line NPA Program, the Commission will
20 reduce barriers to electrification, further California’s public health, air quality and climate
21 objectives, and reduce cost and risk for all gas ratepayers. With a Service Line NPA
22 Program, eligible gas customers will now have the choice to fully electrify with the help
23 of an incentive instead of having to accept gas service line replacement and continued
24 dependency on polluting gas appliances. By redirecting funds that PG&E would
25 otherwise spend on replacing gas service lines, eligible gas customers are better
26 resourced to upgrade their home with modern electric appliances and realize the health
27 and safety benefits of improved indoor air quality and access to cooling. In addition,
28 because an incentive level would be set to provide Net Present Value (“NPV”) savings
29 compared to service line replacement, all gas customers benefit. With a far shorter cost-
30 recovery period than pipeline replacement projects, Service Line NPAs also avoid the
31 significant stranded asset risks of new long-term capital investments in the gas system.

32 Eligible customers are under no obligation to electrify in lieu of service line replacement.
33 However, given the number of service line replacements that occur each year and the
34 scalability of a standardized incentive offering, requiring a Service Line NPA Program be

² Exh. PG&E-01, Errata Testimony at 1-14:21–22.

³ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.18(c).

⁴ See Section V, *infra*.

1 part of PG&E’s NPA portfolio will likely significantly increase NPA deployment from
2 the levels currently proposed in PG&E’s GRC Application and mark a meaningful and
3 necessary step forward in pruning the gas system.

4 Accordingly, Sierra Club and NRDC recommend the Commission approve PG&E’s
5 proposed continuation of AEP with the modifications set forth below and require PG&E
6 to implement a Service Line NPA Program as an important complement to its existing
7 NPA programs.

8 For both AEP and the Service Line NPA Program, the Commission should:

- 9 1) Assign behind-the-meter costs of NPA execution regulatory asset treatment with
10 a 10-year cost-recovery period;
- 11 2) Require a mechanism to ensure gas customers benefit from the reduction in
12 capital spending on gas infrastructure that would have otherwise occurred in the
13 absence of NPA deployment;
- 14 3) Increase the \$2 million administrative budget PG&E requested for AEP to \$3
15 million for both programs and classify these costs as operational expenses with
16 any unspent funds returned to gas ratepayers; and
- 17 4) Recover AEP and Service Line NPA Program costs from gas ratepayers.

18 With regard to a Service Line NPA Program, the Commission should require PG&E to
19 offer a program similar to Con Edison’s program with the following features:

- 20 1) A standard electrification incentive no greater than the average avoided cost of
21 service line replacement. We estimate that the lifetime cost to gas customers of
22 replacing a service line connected to a single residential gas meter as part of larger
23 distribution main replacement programs and the Reliability Service Replacement
24 Program is slightly more than \$20,000. To further equity and affordability, we
25 recommend PG&E be directed to offer residential customers facing a service line
26 replacement a base \$15,000 NPA incentive with a \$20,000 NPA incentive for
27 households in Disadvantaged Communities (“DACs”). At this incentive level, we
28 estimate the Service Line NPA Program proposal would save gas customers
29 approximately \$44 million (nominal dollars), or approximately \$3 million (NPV),
30 while avoiding an additional \$8 million in social costs of emissions for every
31 1,000 service line replacements avoided through the Program.
- 32 2) The Program should apply to service lines connected to a residential customer
33 meter that would otherwise be replaced under MAT codes 50B (Reliability
34 Service Replacement Program), 14A (Gas Pipeline Replacement Program), 14D
35 (Plastic Pipe Replacement Program) and 50A (Reliability Pipe Replacement

1 Program). Service lines connected to non-residential customers would continue
2 to be eligible for NPAs under AEP.

3 3) Program implementation similar to Con Edison’s Service Line NPA Program with
4 elements that include:

- 5 • A means for gas customers to verify their eligibility for the Program, such
6 as through an email inquiry to a designated representative or an online
7 look-up tool;
- 8 • Customer outreach, with additional outreach provided to customers in
9 DACs;
- 10 • A list of potential contractors;
- 11 • Review to ensure that, where necessary, in-front-of-meter electrical
12 upgrades occur prior to project execution;
- 13 • A requirement for gas disconnection and gas meter removal as a condition
14 of program participation; and
- 15 • Follow up surveys to enable incorporation of customer feedback to
16 program design updates.

17 4) Coordination to the extent feasible with existing efficiency and electrification
18 programs, including those targeting low-income customers, to maximize available
19 incentives to cease gas service, as well as with local partners that have expressed
20 interest in zonal electrification through the SB 1221 process; and

21 5) Annual reporting on program progress in conjunction with PG&E’s existing AEP
22 reporting.

23 **III. BACKGROUND: PLANNING FOR THE GAS TRANSITION (VESPA)**

24 **Q. What is gas transition planning and what are its key objectives?**

25 **A.** Planning for the gas transition generally refers to proactively managing the potential
26 future rate, bill, equity, workforce and other impacts from the rapid declines in fossil gas
27 use necessary to achieve climate and air quality objectives. Since at least 2019, when
28 Gridworks released the white paper *California’s Gas System in Transition: Equitable,*
29 *Affordable, Decarbonized and Smaller*, there has been a recognition that the shift from
30 gas to electric appliances in homes and buildings has significant implications for gas rates

1 and equitable outcomes for California’s communities.⁵ As Gridworks observed,
2 “[w]ithout active planning and management, the combination of reduced gas usage,
3 increased costs, and a declining customer base will result in exponentially higher gas
4 rates, along with a disproportionate burden on customers unable to afford to implement
5 electrified technologies.”⁶ Gas transition planning seeks to avoid this outcome through
6 strategies that include deployment of alternatives to significant new long-term
7 investments in the gas delivery system not otherwise needed to maintain safety and
8 reliability.⁷

9 More recently, the Commission, together with the California Energy Commission
10 (“CEC”) and California Air Resources Board (“CARB”) jointly addressed gas system
11 planning in their *2024 Joint Agency Staff Paper: Progress Toward a Gas Transition*.⁸
12 Similar to the Gridworks report, the *Joint Agency Staff Paper* recognized that:

13 Thoughtful planning of the transition away from fossil gas will help
14 achieve California’s climate goals while helping the State identify and
15 evaluate actions that can reduce rate and bill impacts while also ensuring
16 safe and reliable operation of the gas system, supporting public health,
17 prioritizing disadvantaged communities, and advancing opportunities to
18 engage the affected gas workforce.

19 In order to provide both reliability and reasonable rates and bills, it will be
20 critical that utilities maintain the right balance of investment in gas
21 infrastructure. If too much infrastructure is maintained at too high a cost,
22 and those costs must be spread across a declining customer base, gas
23 transportation rates could increase to unsustainable levels.⁹

24 **Q. What are potential impacts to gas rates when gas demand declines without**
25 **meaningful reductions in long-term investments in the gas system?**

26 **A.** The CEC has begun to model end-use gas rates under various gas demand and gas system
27 investment scenarios.¹⁰ The CEC estimated PG&E residential gas transportation rates

⁵ See Gridworks, *California’s Gas System in Transition: Equitable Affordable, Decarbonized and Smaller* (2019), https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf.

⁶ *Id.* at 2.

⁷ *Id.* at 3.

⁸ CPUC, CEC & CARB, *2024 Joint Agency Staff Paper: Progress Toward a Gas Transition* (Feb. 22, 2024), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M525/K660/525660391.PDF>.

⁹ *Id.* at 6.

¹⁰ 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).

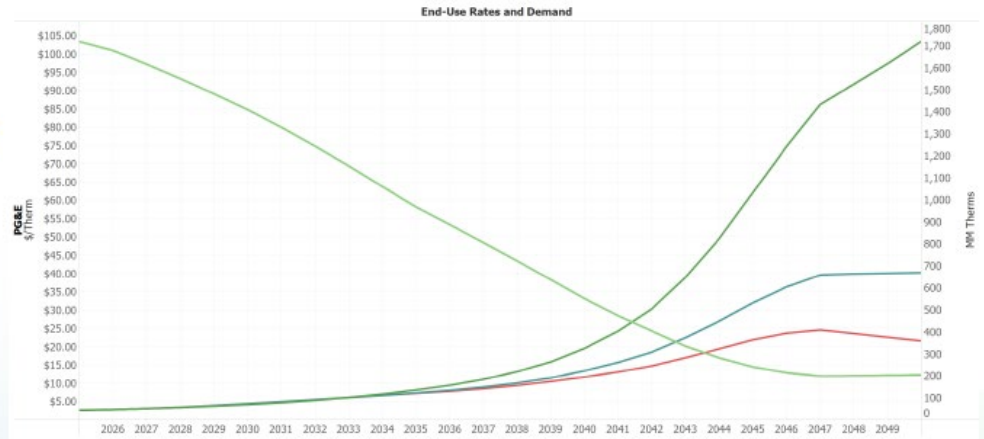
1 would increase close to fifty-fold by 2050, from \$2.14/therm in 2025 to \$102.76/therm in
2 2050, assuming continued business-as-usual investments in the gas system and declines
3 in gas demand that would occur where buildings are electrified at a significantly slower
4 pace than under the CARB Scoping Plan.¹¹



End-Use Rates: PG&E

PG&E Residential End-Use Rates

- GT AAFS 2.5 Demand Scenario
- Constant Growth RR
- Front Load RR
- Pruning RR



5
6 As shown in the graph above, scenarios where there was a near-term increase in the
7 revenue requirement compared to historic levels followed by minimal growth (a “Front
8 Load” scenario) or an increase followed by annual reductions in the revenue requirement
9 (a “Pruning” scenario) resulted in significantly lower rate impacts in outer years.¹²

¹¹ CEC, Docket No. 25-IEPR-03, TN #264052, 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 30 (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>.

¹² The CEC revenue requirement assumptions for each scenario are in the RR Growth Rate Tab at CEC, Docket No. 25-IEPR-03, TN #264052, 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 is front loaded or there is significant pruning of gas system.

1 **IV. BACKGROUND: PAST AEP IMPLEMENTATION AND PG&E’S CURRENT AEP**
2 **REQUEST**

3 **Q. Please describe your understanding of AEP implementation to date. (Vespa)**

4 **A.** PG&E describes AEP as providing “incentive payments to gas customers to convert their
5 gas service to non-pipe alternatives (primarily electric), which avoids continued gas asset
6 spending including upgrades, replacement, and operation and maintenance.”¹³ The dollar
7 amounts paid to PG&E customers for conversions are negotiated incentives.¹⁴ PG&E
8 states that to “determine the appropriate incentive amount, customers are required to
9 obtain contractor bids for the behind-the-meter electrification or other work.”¹⁵ The bids
10 are then evaluated against the NPV of the avoided cost of the traditional gas investment
11 with a conversion “deemed cost-effective when the total cost to convert is less than the
12 projected cost of mitigating gas asset risks through conventional means.”¹⁶ The average
13 cost of both commercial and residential meter conversion was approximately \$85,000 per
14 meter.¹⁷ PG&E reported that the NPV of the avoided gas infrastructure work that would
15 have been required for the 12 projects executed in 2024 was approximately \$1.44
16 million.¹⁸

17 The number of annual conversions PG&E has executed through AEP is set forth in the
18 table below.¹⁹ The type of gas infrastructure investment avoided through meter
19 conversion varies by project and has included high pressure regulator (“HPR”) projects,
20 distribution mains, and distribution service lines, with the majority of meter conversions
21 from HPR projects.²⁰

	Residential Meter Conversions	Commercial Meter Conversions	Total Meter Conversions
2020	-	-	25
2021	13	3	16
2022	2	6	8
2023	5	2	7
2024	6	6	12

22

¹³ Exh. PG&E-03, Errata Testimony at 9-17:11-15.

¹⁴ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.13(a).

¹⁵ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.17.

¹⁶ *Id.*

¹⁷ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.18(b).

¹⁸ Attach. 3, PG&E AEP 2024 Annual Report at 3.

¹⁹ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.18(c).

²⁰ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-02, Q.6; Sierra Club-PG&E-05, Q.10.

1 **Q. Do the pilot zonal electrification pilot projects authorized under Senate Bill 1221**
2 **obviate the need for AEP? (Vespa)**

3 **A.** No. SB 1221 authorizes no more than 30 NPA pilot projects across the state with the
4 consent of at least 67 percent of property owners with gas service within the pilot project
5 boundary.²¹ The legislation specifically provides that a “pilot project where a gas
6 corporation obtains the consent of 100 percent of property owners with natural gas
7 service within the pilot project boundary shall not count toward the 30 pilot project
8 limit.”²² AEP is therefore an important complement to SB 1221 pilots by targeting
9 projects where there is 100 percent consent (likely those with few affected property
10 owners) and that offer the potential for significant savings and the need for individualized
11 analysis.

12 **Q. How has PG&E recovered costs of the AEP to date? (Vespa)**

13 **A.** In PG&E’s 2023 GRC decision, the Commission found that “the replacement of gas
14 services and equipment should not be authorized if such funds can be repurposed to
15 support electrification that obviates the need for those gas mains, or costs associated with
16 closing those mains.”²³ The 2023 PG&E GRC Decision authorized approximately \$30
17 million in funding for AEP consisting of \$2.6 million for administrative expenses, \$10.3
18 million reallocated from PG&E’s request funding its Reliability Service Replacement
19 Program (MAT 50B) and \$17.85 million reallocated for PG&E’s requested funding for
20 its High-Pressure Regulator Program (MWC 2K).²⁴ The 2023 PG&E GRC Decision
21 required PG&E to establish a one-way balancing account for the program that would
22 track funds as expense, although alternatives to other categories of gas infrastructure

²¹ S.B. 1221, 2023–2024 Reg. Sess., adding Pub. Util. Code § 663(a), (b)(4) (Cal. 2024).

²² *Id.* § 663(a).

²³ D.23-11-069, *Decision on Test Year 2023 General Rate Case for Pacific Gas and Electric Company*, at 82 (Nov. 17, 2023) (“D.23-11-069”),

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M520/K896/520896345.pdf>.

²⁴ *Id.* at 223.

1 could be capitalized.²⁵ PG&E stated it has treated all costs to execute electrification
2 conversions under AEP as expense costs.²⁶

3 **Q. How is PG&E proposing to recover AEP costs in this GRC cycle? (Vespa)**

4 **A.** PG&E is requesting close to \$21.9 million beginning in 2027 for AEP, with
5 approximately \$19.8 million for 180 annual meter conversions and \$2 million for
6 program implementation.²⁷ PG&E is proposing that “work forecasted in the AEP be
7 treated as regulatory assets by amortizing the amount spent each year starting in January
8 of the year of spend over the course of 15 years.”²⁸ PG&E seeks to modify AEPBA, its
9 AEP balancing account, “to track and recover electrification behind-the-meter costs as a
10 regulatory asset with a full rate of return.”²⁹ At the end of the GRC cycle, PG&E
11 proposes that “any over-collected balance in the electric AEPBA will be refunded to
12 electric distribution customers through a transfer to the Distribution Revenue Adjustment
13 Mechanism (DRAM) in the Annual Electric True-Up Advice Letter (AET) or as
14 otherwise authorized by the Commission.”³⁰ In requesting AEP funds, “PG&E has not
15 reduced its capital forecast in any infrastructure categories (e.g. MAT 50B or MWC 2K)”
16 to account for gas infrastructure projects that are avoided through AEP projects.³¹

²⁵ *Id.* at 82, 141, 901 at Ordering Para. #6 (“The capital funding amount Pacific Gas and Electric Company (PG&E) requested in this general rate case (1) to replace gas service lines through MAT 50B that were not authorized (\$10.3 million), and (2) to remove, rebuild or update High Pressure Regulator stations in MWC 2K that were not authorized (\$17.853 million) shall be repurposed as operations and maintenance (O&M) expense or capital, depending on how the funds are used, to incentivize the transition of home energy usage from gas to electric by adopting such funds in the amount not authorized in MAT 50B and MWC 2K to the Alternate Energy Program...PG&E shall file a Tier 1 Advice Letter to create a one-way Alternative Energy Program Balancing Account to track the funds diverted from accounts for replacing gas assets that are added to the Alternative Energy Program. This balancing account shall track funds used for the Alternative Energy Program as expense, except that Alternative Energy Program expenditures may be treated as capital when they are incurred for activities which would be treated as capital if they occurred under other gas infrastructure MAT codes.”)

²⁶ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-05, Q.10(a).

²⁷ Exh. PG&E-03, Errata Testimony at 9-18, Table 9-6; 9-19:13, 24.

²⁸ *Id.* at 9-19:16–18.

²⁹ Exh. PG&E-10, Errata Testimony at 16-9:10–11.

³⁰ *Id.* at 16-10:28–16-11:1; *see also* Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-18, Q.2.

³¹ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-05, Q.11.

1 **V. SERVICE LINE NPA PROGRAM SUMMARY**

2 **Q. Please provide a high-level description of the Service Line NPA Program.**
3 **(Vespa/Velez)**

4 **A.** To limit avoidable capital investments in the gas system, the Commission would require
5 PG&E to offer households facing a service line replacement a standardized, voluntary
6 incentive to electrify and avoid the costs that PG&E would otherwise have incurred from
7 replacing these customers' service lines. Similar to a Service Line NPA Program being
8 implemented by Con Edison in New York, the program would have various steps to
9 ensure adequate outreach, connection to potential contractors, a review to ensure that any
10 necessary in-front-of-meter electrical upgrades occur prior to project execution, customer
11 gas disconnection and gas meter removal, and follow up surveys to enable incorporation
12 of customer feedback to program design updates. Like our recommendations for AEP,
13 PG&E would recover costs to implement the Service Line NPA from gas customers over
14 a 10-year period as a regulatory asset with a mechanism to ensure gas ratepayers benefit
15 from the reduced capital spending on service line replacements from NPA execution.

16 We recommend the Service Line NPA Program be available to residential customers
17 scheduled for a service line replacement under MATs 14A, 14D, 50A, and 50B.³² Based
18 on our estimate of the NPV cost of avoided service line replacement under these MAT
19 codes, we recommend a base incentive of \$15,000 with a \$20,000 enhanced incentive for
20 residential gas customers in DACs. At these incentive levels, a program that converts
21 1,000 participants in Year 1 would save gas customers as a whole approximately \$44
22 million (nominal dollars), or \$3 million (NPV), while delivering an additional \$8 million
23 in avoided social costs of emissions.³³

24 **Q. Why should the Commission direct PG&E to implement a Service Line NPA**
25 **Program? (Vespa)**

26 **A.** A Service Line NPA program is an important complement to other emerging NPA
27 programs. SB 1221 pilots are extremely limited in number and intended to target larger
28 projects where 100 percent customer consent cannot be obtained. AEP projects require
29 individualized cost-effectiveness assessments that would be administratively
30 cumbersome and unnecessary for routine individual service line replacement projects.

³² The proposed incentive level would apply where the customer has the only meter connected to the service line. To the extent the program is offered where the service line connects to more than one meter, the maximum incentive level per customer would be divided among all impacted customers and contingent on all impacted customers agreeing to NPA deployment to enable pipeline decommissioning.

³³ See Section VII, *infra*.

1 Unlike AEP, customer incentives to electrify in lieu of service line replacement can be
2 standardized, thereby providing the opportunity for scalability and avoiding the case-by-
3 case cost-effectiveness analysis needed for larger NPA projects. Because the vast
4 majority of service lines connect to a single customer meter, service line replacements are
5 also the least complicated type of NPA to execute and provide the opportunity to offer
6 NPAs to households across PG&E's service territory through standardized voluntary
7 incentives. In addition, because service lines end at the customer meter, service line
8 decommissioning does not present hydraulic feasibility concerns.³⁴

9 A Service Line NPA Program can also enable the partial success of zonal electrification
10 projects. If projects being scoped for potential SB 1221 and AEP prove infeasible due to
11 a lack of consent or other factors, the Service Line NPA Program can enable at least
12 some homes to fully electrify and depart the gas system. For example, PG&E replaces an
13 average of 67 services per Plastic Pipe Replacement (MAT 14D) project.³⁵ Obtaining
14 sufficient consent from this many property owners to proceed with a zonal electrification
15 is significantly more challenging than an electrification project targeting a single
16 customer. A Service Line NPA Program is an important tool to reduce the scope and
17 complexity of the gas replacement project by enabling interested homeowners to receive
18 an electrification incentive and avoid replacing the service line to their property without
19 the need for agreement or coordination between the other property owners impacted by
20 the larger replacement project.

21 In addition, new service lines pose significant stranded asset risks. A service line
22 replaced in 2027 would not be fully depreciated until at least 2082.³⁶ This is decades
23 after California's 2045 carbon neutrality objective.³⁷ If a home fully electrifies by 2045
24 to help achieve California's greenhouse gas reduction requirements, the service line
25 connected to that home would not be used and useful for over 35 years of its service
26 life.³⁸ Avoiding service line replacement through Service Line NPAs avoids the
27 likelihood that the service line will not be utilized for the entirety of its depreciation
28 period.

³⁴ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-14, Q.7.

³⁵ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-11, Q.2(b).

³⁶ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.19 (service life of assets recorded under gas distribution pipeline MAT codes between 55-60 years).

³⁷ Cal. Health & Safety Code § 38562.2.

³⁸ See CARB, *2022 Scoping Plan for Achieving Carbon Neutrality*, at 212 (Nov. 16, 2022), https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp_1.pdf ("Achieving carbon neutrality must include transitioning away from fossil gas in residential and commercial buildings.").

1 **Q. What are the opportunities for deployment of a Service Line NPA in PG&E service**
 2 **territory? (Vespa)**

3 **A.** The opportunities for deployment of a Service Line NPA are significant. Between 2022–
 4 2024, PG&E replaced over 15,000 service lines each year, approximately 14,000 of
 5 which were connected to a single customer meter. I calculated this number by reviewing
 6 the service line replacement data for PG&E’s various service line replacement programs.
 7 Most service lines are replaced as part of larger gas distribution line replacement projects
 8 that include replacement of the distribution main. PG&E has three pipeline replacement
 9 programs that include service replacements described in its Gas Operation testimony
 10 (Exh. PG&E-03), the Gas Pipeline Replacement Program (MAT 14A), the Plastic Pipe
 11 Replacement Program (MAT 14D), and the Reliability Pipe Replacement Program (MAT
 12 50A).³⁹ The approximate number of service lines replaced under each program from
 13 2022–2024 and the number of meters the lines connect to are set forth in the following
 14 excerpt from a PG&E data request response:⁴⁰

Program	Year	Total Services Replaced ^(a)	Core Residential Meters	Core Commercial Meters	Industrial Meters	Noncore Meters	Single meter Services ^(b)	2-5 meter Services ^(b)	>5 meter Services ^(b)
GPRP (MAT 14A)	2022 - 2024	6,106	8,299	679	2	1	5,170	1,013	118
Plastic Pipe Replacement (MAT 14D)	2022 - 2024	35,827	44,383	1,392	2	1	32,282	3,802	422
Reliability Pipe Replacement (MAT 50A)	2022 - 2024	2,563	3,931	159	0	0	1,951	477	78

(a) Excludes counts where a service was unable to be correlated with the meter class data.
 (b) Total services replaced varies slightly as data availability for count of meters per service varies from meter class data.

15
 16 PG&E collectively replaced 44,496 services between 2022 and 2024 under these three
 17 programs, of which 39,403, or 88.6 percent, connected to a single customer meter. The

³⁹ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-02, Q.2.

⁴⁰ *Id.*; see Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.5(b) (PG&E was unable to correlate with meter class data approximately 1,001, 3,948, and 926 services from MAT 14A, MAT 14D, and MAT 50A, respectively.).

1 39,403 services connected to a single customer meter that were replaced between 2022
2 and 2024 average to 13,134 replacements each year.

3 PG&E also has standalone service line replacement programs. The Reliability Service
4 Replacement Program (MAT 50B) is a standalone service line replacement program that
5 PG&E states “proactively replaces services to improve system safety and maintain
6 compliance with pipeline regulations.”⁴¹ PG&E annually replaced an average of 480
7 service lines connected to a single customer meter under this program between 2022 and
8 2024.⁴²

9 PG&E also has “a separate program (MAT 50G/M) to replace services where leaks are
10 found.”⁴³ MAT 50G refers to Simple Distribution Service Replacements, which “tracks
11 simple service (i.e. single gas service) replacement costs.”⁴⁴ PG&E replaced an average
12 of 848 residential service lines annually under 50G between 2022–2024.⁴⁵

13 **Q. Are you aware of examples of other utilities offering customers alternatives to**
14 **service line replacements? (Vespa)**

15 **A.** Yes. Con Edison has a Service Line Replacement NPA program it markets as the Energy
16 Exchange Program.⁴⁶ The program targets customers connected to the gas system via
17 pre-1972 services and provides incentives to fully disconnect from the gas system.⁴⁷
18 Incentives provided under the Energy Exchange Program are as follows:⁴⁸

⁴¹ Exh. PG&E-03, Errata Testimony at 4-41:3–5, 15–16 (“[s]ervice replacements that are performed in conjunction with main replacements are not funded in this program.”).

⁴² Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.4(a).

⁴³ Exh. PG&E-03, Errata Testimony at 4-41:16–17; *see also* Exh. PG&E-03, Errata Testimony Vol. 2, at 8-36.

⁴⁴ Exh. PG&E-03 at 8-36:22–23. MAT 50M is for complex service (i.e., branch service or later meter set) replacement costs. *Id.* at 8-36:22–24.

⁴⁵ Attach. 2, PG&E Supplemental Response to Data Request Sierra Club-PG&E-01, Q.6(a) (970 residential MAT 50G replacements in 2022, 866 in 2023 and 708 in 2024).

⁴⁶ Attach. 4, Con Edison, *Non-Pipes Alternatives Implementation Plan*, at 12–13 (Nov. 18, 2024), <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B20D54093-0000-C55C-B8E2-2BBA133E981F%7D>. *See also* Con Edison, *Energy Exchange Program*, <https://www.coned.com/en/save-money/rebates-incentives-tax-credits/rebates-incentives-tax-credits-for-residential-customers/energy-exchange> (last visited Feb. 5, 2025).

⁴⁷ Attach. 4, Con Edison, *Non-Pipes Alternatives Implementation Plan*, *supra* note 46, at 12–13.

⁴⁸ Con Edison, *Energy Exchange Program*, *supra* note 46.

Building Type	SINGLE-FAMILY	2+ UNITS	SMALL BUSINESS + NONPROFIT	COMMERCIAL + INDUSTRIAL
BASE INCENTIVE	up to \$10,000	up to \$15,000	up to \$10,000	up to \$10,000
ENHANCED INCENTIVES FOR DISADVANTAGED COMMUNITIES*	up to \$15,000	up to \$20,000	up to \$15,000	up to \$15,000

1
2 Con Edison hosts a webpage for customers to submit interest forms and choose preferred
3 contractors.⁴⁹ As set forth in Con Edison’s Non-Pipes Alternative Implementation Plan,
4 Con Edison implements the program through a network of pre-approved Participating
5 Contractors with the following process:⁵⁰

- 6 • Once the customer has selected a Participating Contractor, the contractor
7 performs a site survey of the existing conditions and documents existing gas
8 appliances.
- 9 • Following a site visit, the Participating Contractor works with the customer to
10 decide on specific electric appliances to replace the existing gas appliances and
11 review the necessary electrical work and gas piping/equipment removal.
- 12 • The Participating Contractor submits a program application, which is vetted to
13 assess if electric service upgrades are required. Projects with adequate electrical
14 service are granted a Preliminary Incentive Offer Letter (“PIOL”), as long as all
15 other program application requirements are met. These requirements include site
16 photos, appliance nameplate photos, electrical panel photos, etc.
- 17 • Projects that require electrical service upgrades must allow the service upgrade to
18 be completed before a PIOL is extended and installation can proceed. This
19 process prioritizes safe and reliable electric service. After the customer and
20 Participating Contractor review and accept the PIOL, the Company issues a blank
21 Completion Certificate to be filled out and returned to the Company after
22 installation is completed. A Participating Contractor can proceed with installation
23 once they have received the Company’s Completion Certificate.
- 24 • After installation, the customer must close their gas account and work with the
25 Participating Contractor to file a separate case through Con Edison’s Project
26 Center requesting gas service disconnection and gas meter removal. The case
27 number associated with the gas request is added to the Completion Certificate, in

⁴⁹ *Id.*

⁵⁰ *Id.* at 16–18.

1 addition to confirmation that the customer's gas account has been closed.
2 Additional project documents and details also accompany the Completion
3 Certificate document before the formal submission is made to the Company to
4 indicate installation has been completed and Post Inspection and Final Review
5 can occur.

- 6 • The Company performs an inspection of the installation (on-site or desk review),
7 performs the Final Review, then submits the project for payment.
- 8 • Finally, the Company sends out follow-up customer satisfaction surveys to all
9 customers to assess satisfaction, identify and mitigate any issues, and enable
10 incorporation of customer feedback into program design updates. When full
11 electrification of each customer is confirmed, the Company will schedule the
12 service to be disconnected, allowing the service pipe to be abandoned.

13 While specific implementation details can be left to PG&E, the process by which Con
14 Edison executes Service Line NPAs can serve as a model for a Service Line NPA
15 program in California.

16 **VI. COST RECOVERY RECOMMENDATIONS FOR AEP AND A SERVICE LINE NPA** 17 **PROGRAM**

18 This section provides the basis for Sierra Club and NRDC's recommendation that the
19 costs of NPA execution for both AEP and a Service Line NPA program be treated as
20 regulatory assets with a 10-year cost recovery period with costs recovered from gas
21 ratepayers. We also provide options for the Commission to ensure gas customers benefit
22 from NPA deployment through reductions in capital spending on the new gas
23 infrastructure the NPA avoids. Finally, we recommend the Commission approve \$3
24 million for joint program administration costs for AEP and the Service Line NPA
25 Program, with any unspent funds returned to gas ratepayers.

26 **Q. Do you agree that the Commission should allow PG&E to recover behind-the-meter** 27 **costs of NPA projects as a regulatory asset? (Velez)**

28 **A.** Yes. In this instance, recovery of behind-the-meter costs as a gas regulatory asset is
29 appropriate because of the ratepayer and societal benefits of NPAs and because the
30 counterfactual to NPA execution is a gas infrastructure replacement project that would be
31 fully capitalized over a much longer cost-recovery period.

32 NPAs to new capital investments in fossil fuel infrastructure provide a host of benefits.
33 For example, electrifying gas end uses that would otherwise be served by a new gas
34 pipeline or other gas infrastructure furthers California's climate and air quality goals by

1 reducing fossil fuel reliance and its corresponding greenhouse gas, air quality, and public
2 health impacts. In addition, PG&E depreciates new capital investments in the gas
3 distribution system over 55 to 60 years.⁵¹ Accordingly, while gas customers would be
4 expected to pay back the costs of a gas line replaced in 2030—and the associated annual
5 rate of return—until at least 2085, an NPA treated as a regulatory asset with a 10-year
6 cost recovery period would be paid off by 2040. As the Commission has previously
7 determined:

8 One of the primary economic risks of the transition is that gas distribution
9 infrastructure will become underutilized or even abandoned (‘stranded’)
10 before the utility has recovered the entire investment cost from
11 ratepayers.... An increase in stranded assets would lead to increasing rates
12 for those customers who continue to use gas. As more of the system
13 becomes underutilized or abandoned, those increases could eventually
14 become exponential.⁵²

15 NPAs address these significant stranded asset concerns because utilities will recover the
16 full cost of the investment decades before they would have had the utility instead
17 proceeded with the gas infrastructure replacement project the NPA avoids. Moreover, in
18 contrast to new investments in the gas system, the climate benefits of electrification
19 increase over time as California’s electric grid becomes increasingly decarbonized.
20 Accordingly, the electrification incentives provided through NPAs will support
21 installation of equipment that is compatible with a decarbonized energy system and
22 expected to remain in use without becoming a stranded investment.

23 Particularly at this early stage of NPA implementation, categorizing NPA behind-the-
24 meter (“BTM”) costs as costs that are recovered in the year they are incurred, rather than
25 a regulatory asset depreciated over 10 years with a reasonable rate of return,
26 disincentivizes their execution and the corresponding climate, public health, equity and
27 ratepayer benefits that would otherwise be realized. Indeed, on top of allowing NPA
28 implementation costs to be treated as regulatory assets, the New York Public Service
29 Commission approved a cost-recovery mechanism for proposed NPAs by Con Edison
30 where “shareholders would retain a 30 percent share of initial net benefits as determined
31 by as societal cost test.”⁵³ While the Commission need not provide this type of

⁵¹ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.19.

⁵² CPUC, CEC & CARB, *2024 Joint Agency Staff Paper: Progress Towards a Gas Transition*, *supra* note 8, at 31.

⁵³ See State of New York Public Service Commission, *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}>.

1 shareholder incentive, I agree with PG&E that the Commission should afford a rate of
 2 return to NPA projects to ensure utilities have a similar incentive to execute climate
 3 friendly alternatives that avoid new long-term investments in fossil-fuel infrastructure.

4 PG&E also proposes regulatory asset treatment and “amortization of the costs in rates
 5 over time to smooth the impact on customers’ rates.”⁵⁴ I agree that classifying the costs
 6 of NPA deployment as operational costs that are recovered the year they are incurred has
 7 significant near-term bill impacts compared to spreading those costs over time and further
 8 warrants regulatory asset treatment in this instance. To illustrate the difference, Table 1
 9 below shows the lifetime ratepayer savings and Year 1 bill impacts of recovering \$1
 10 million in NPA costs as operational expenses recovered over one year or as regulatory
 11 assets over 10 or 15 years. The bill impacts presented below are compared against the
 12 default of capitalizing \$1 million in service line replacement costs over 55 years that
 13 would occur were pipeline replacement to proceed. The table presents lifetime gas
 14 revenue requirement savings of the NPA investment in both nominal dollars and net-
 15 present value (“NPV”), and it presents the total Year 1 bill impact of the NPA investment
 16 on non-participating gas customers.⁵⁵

17 **Table 1: Comparison of NPA Revenue Requirement and Bill Impacts Across Cost**
 18 **Recovery Options⁵⁶**

Cost Recovery Method	Lifetime Cost Savings Compared to Gas Replacement (Nominal Dollars)	Lifetime Cost Savings Compared to Gas Replacement (Net-Present Value)	Year 1 Bill Impact, Non-Participating Gas Customer
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

⁵⁴ Exh. PG&E-10, Errata Testimony at 16-10:2-3.

⁵⁵ The NPV calculation assumes a customer-perspective discount rate of 5 percent, as discussed further in Section 5.1 of the NPA Cost Analysis Tool Methodology Document (Attach. 5).

⁵⁶ Results were generated using the NRDC NPA Cost Analysis Tool (Attach. 6). 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.

1 The impacts presented in the table above would only scale proportionately with greater
 2 NPA investment. Categorizing the costs of executing an NPA as a typical operational
 3 expense would have much higher Year 1 impacts than if these costs were treated as a
 4 regulatory asset with costs recovered over 10 or 15 years.

5 From a revenue requirement perspective, Table 2 below presents the lifetime ratepayer
 6 costs of recovering \$1 million in pipeline replacement costs capitalized over a 55-year
 7 period as compared to a \$1 million NPA treated as operational expenses recovered in
 8 Year 1 or as regulatory assets with costs recovered over 10 or 15 years.⁵⁷ As shown
 9 below, a \$1 million upfront investment capitalized over 55 years increases costs
 10 significantly compared to a \$1 million upfront investment capitalized over 10 or 15 years.
 11 This is attributable to the difference in returns and taxes that gas customers would pay the
 12 utility over the lifetime of the investment. While paying the entirety of these costs in
 13 Year 1 would have the lowest lifetime cost, as set forth above in Table 1, it would also
 14 result in more than a 12-fold increase in Year 1 bill impacts compared to amortization
 15 over 10 years.

16 **Table 2: Lifetime Revenue Requirement (Nominal Dollars) of Each Investment**
 17 **Option**⁵⁸

	\$1M Pipeline Replacement Capitalized Over 55 Years	\$1M NPA Investment – No Reg Asset	\$1M NPA Investment – 10-Year Depreciation	\$1M NPA Investment – 15-Year Depreciation
Lifetime Cost (Nominal Dollars)	\$3.78 million	\$1 million	\$1.46 million	\$1.72 million

18
 19 **Q. Why do you recommend the Commission approve a 10-year cost-recovery period as**
 20 **opposed to the 15-year cost recovery proposed by PG&E? (Vespa/Velez)**

21 **A.** While a 15-year amortization period for NPA projects is far superior to the 55- to 60-year
 22 amortization period that would apply to counterfactual gas infrastructure investments, a
 23 10-year cost recovery period better mitigates the potential affordability and equity
 24 impacts from the gas transition. For projects implemented in 2030, a 10-year cost
 25 recovery period means project costs are fully paid off by 2040 as opposed to 2045 under

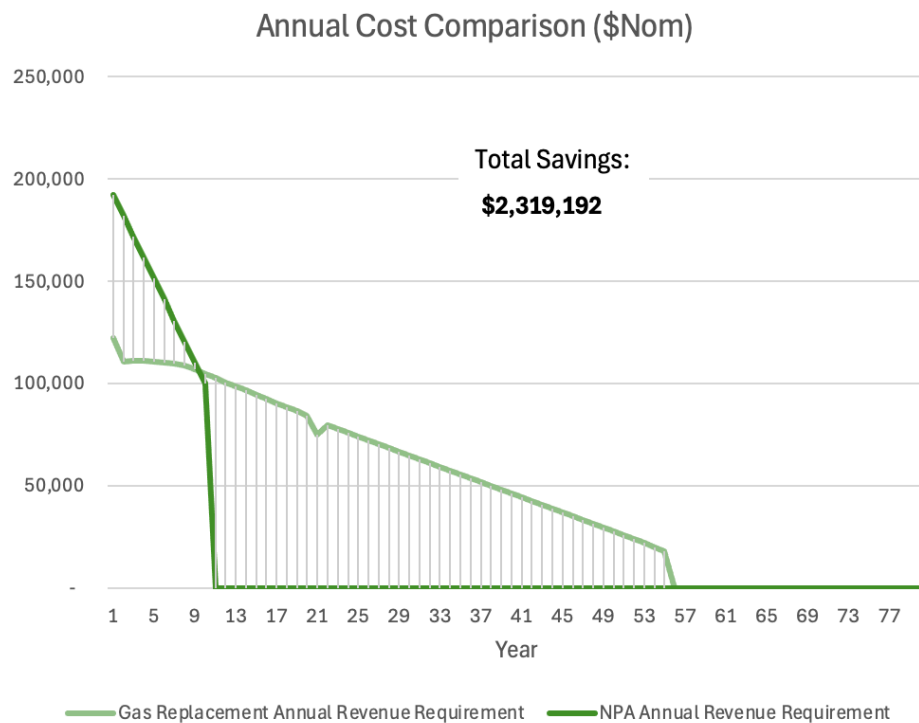
⁵⁷ *Id.*

⁵⁸ See executable Attach. 6, NPA Cost Analysis Tool, *Cost Recovery Comparison* tab, for scenario run documentation.

1 a 15-year cost recovery period. As noted above in Section III, the CEC forecasts gas
 2 rates will more significantly escalate after 2040 under scenarios of gas demand decline
 3 coupled with continued business-as-usual investments in the gas system. Accordingly, a
 4 10-year cost recovery better avoids rate burdens in outer years.

5 A shorter cost-recovery period also reduces total project costs because the investment is
 6 paid off more quickly without creating significantly increased Year 1 bill impacts
 7 compared to a 15-year cost-recovery period. As shown above in Table 1, while a 10-year
 8 cost recovery period does have higher Year 1 bill impacts than a 15-year recovery period,
 9 the difference is less than half a cent over the entire year for a \$1 million investment. In
 10 addition, bill impacts are highest in Year 1, after which the annual revenue requirement
 11 of the NPA investment declines each year until the investment is fully depreciated. As
 12 also shown above in Table 1, increasing the NPA depreciation period from 10 to 15 years
 13 reduces the total lifetime savings of the NPA, since ratepayers pay the utility a return on
 14 the investment over a longer time period.

15 **Figure 1: Annual Cost Comparison -- \$1M Gas Replacement (55-Yr Depr.) vs \$1**
 16 **NPA Investment (10-Yr Depr.)**



17 Given these dynamics, a 10-year depreciation period better balances stranded asset risk,
 18 long-term cost savings and Year 1 NPA bill impacts. As shown in Figure 1 above, a \$1
 19

1 million NPA depreciated over 10 years yields significant cost savings for gas customers
2 compared to a \$1 million service replacement depreciated over 55 years.

3 **Q. Do you agree with PG&E’s proposal to recover AEP costs from electric ratepayers?**

4 **A.** No. Whereas AEP was previously funded by gas customers, PG&E is now proposing
5 that AEP electrification incentive costs “be recovered from electric distribution
6 customers.”⁵⁹ The Commission should reject this approach and continue to fund NPA
7 programs through gas rates. Because NPAs avoid long-term capital investments in the
8 gas system that would otherwise occur, gas customers are their primary beneficiaries.
9 Allocating NPA costs to gas customers also best aligns with cost causation principles
10 because the gas investments that NPAs are designed to replace are driven by gas system
11 needs, not by electric customers. Indeed, PG&E has made no showing nor attempted to
12 quantify benefits of NPA deployment to electric customers to justify shifting the entirety
13 of the costs of NPA execution onto electric ratepayers. Moreover, PG&E’s gas and
14 electric service territories do not fully overlap. PG&E’s proposal would therefore either
15 appear to exclude viable NPA projects within PG&E’s gas service territory but outside its
16 electric service territory, such as in regions where electric service is provided by a
17 municipal utility Sacramento Municipal Utility District (“SMUD”)—or, require PG&E
18 electric ratepayers fund NPA projects in those areas. For these reasons, AEP costs should
19 continue to be funded by PG&E’s gas customers.

20 **Q. How is PG&E ensuring that AEP projects reduce spending on new capital**
21 **investments in the gas system? (Vespa)**

22 **A.** PG&E does not appear to propose a mechanism to ensure ratepayers realize the savings
23 from NPA deployment. In requesting \$19.8 million for AEP projects, PG&E has not
24 reduced its capital request for other gas infrastructure categories.⁶⁰ In response to Sierra
25 Club discovery, PG&E stated that it “forecasts at the MAT code level based on what is
26 necessary and achievable for each individual program to maintain the safety and
27 reliability of the gas system.”⁶¹ It then stated that AEP “is designed to deliver a portfolio
28 of projects that cost-effectively mitigates risk, while reducing greenhouse gas emissions
29 from the gas system.”⁶² However, the benefit of NPAs is to both reduce greenhouse gas
30 emissions *and* reduce capital spending on new gas infrastructure. Rather than substitute
31 for new capital investments in the gas system, PG&E’s funding proposal for AEP appears

⁵⁹ Attach. 2 PG&E Response to Data Request Sierra Club-PG&E-18, Q.2; *see also* D.23-11-069 at 901 (repurposing funds requested for gas infrastructure replacement to AEP).

⁶⁰ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-05, Q.11.

⁶¹ *Id.*

⁶² *Id.*

1 to be in addition to those investments, thereby undermining a key benefit of NPA
2 execution.

3 **Q. How should the Commission ensure NPA deployment results in a corresponding**
4 **reduction in capital investment in the gas system? (Vespa)**

5 **A.** There could be multiple ways to account for reductions in capital spending on new gas
6 infrastructure as a result of NPA deployment. What is important is that a mechanism is
7 included as part of NPA program approval to ensure gas customers do not pay for both
8 the NPA and the gas infrastructure investments the NPA avoids.⁶³

9 One option could be for the Commission to allow PG&E to use approved capital funds
10 for gas infrastructure projects for NPAs where feasible and cost-effective, with a
11 mechanism to account for a shorter 10-year cost-recovery period for NPA deployment.
12 Allowing PG&E to use funds approved for pipeline replacement projects for cost-
13 effective NPAs also better aligns with gas transition planning by recognizing approved
14 costs are intended to address pipeline safety and reliability, not predetermine the specific
15 means by which safety and reliability is achieved. If the safety and reliability concern
16 can be addressed through NPA implementation and pipeline decommissioning rather than
17 replacement, this is an appropriate use of approved funds. This approach is consistent
18 with the Commission’s reasoning in its 2023 GRC Decision, which found that “the
19 replacement of gas services and equipment should not be authorized if such funds can be
20 repurposed to support electrification that obviates the need for those gas mains, or costs
21 associated with closing those mains.”⁶⁴ As part of annual reporting, PG&E can identify
22 the number of executed projects by MAT code and their cost savings compared to
23 pipeline replacement. The savings can then inform its next GRC Application.

24 New York uses an “NPA Adjustment Mechanism.” NPA costs are recovered through a
25 Monthly Rate Adjustment (“MRA”) that reduces gas infrastructure costs to account for
26 displaced capital projects.⁶⁵ Under New York’s approach:

⁶³ As noted below in Section V, the same mechanism should be used for AEP and the Service Line NPA Program.

⁶⁴ D.23-11-069 at 82.

⁶⁵ Attach. 7, Excerpts from State of New York Public Service Commission, *Joint Proposal*, Case 25-E-0072/73, at 24 (Nov. 5, 2025). *See also* NY Public Service Commission, Case 25-E-0072/73, Order Adopting Terms of a Joint Proposal and Establishing Electric and Gas Rate Plans at 58-60 (Jan. 22, 2026), <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={800DE79B-0000-C74C-9247-B3A408818830}&DocTitle=Order%20Adopting%20Terms%20of%20a%20Joint%20Proposal%20and%20Establishing%20Electric%20and%20Gas%20Rate%20Plans> (adopting proposed NPA cost recovery mechanism).

1 To the extent such new NPAs result in the Company displacing a capital
2 project reflected in the Average Gas Plant In Service Balances, the
3 balance(s) will be reduced to exclude the forecasted net plant associated
4 with the displaced project. The carrying charge on the reduction of the
5 Average Gas Plant In Service Balances that would otherwise be deferred
6 for customer benefit will instead be applied as a credit against the recovery
7 of the NPA in the MRA. In the event the carrying charge on the net plant
8 of any displaced project is higher than the NPA recovery, the difference
9 will be deferred for the benefit of customers.⁶⁶

10 In lieu of a system involving rate adjustment mechanisms and carrying charges, the
11 Commission could also simply reallocate requested funds for gas capital infrastructure to
12 AEP and the Service Line NPA program similar to its 2023 GRC Decision, with any
13 unspent funds returned to ratepayers.⁶⁷ However, for the reasons discussed above, unlike
14 the 2023 GRC Decision, reallocated funds for NPA execution should be afforded
15 regulatory asset treatment over a 10-year cost recovery period.

16 **Q. To the extent the Commission prefers to set an NPA program budget instead of**
17 **allowing PG&E to utilize funds approved for new gas infrastructure projects for**
18 **NPA deployment, what is your recommended level of program funding? (Vespa)**

19 **A.** As set forth in the response to the previous question, the Commission could allow PG&E
20 to use approved capital funds for gas infrastructure projects for NPAs where feasible and
21 cost-effective, with a mechanism to account for shorter 10-year cost-recovery period for
22 NPA deployment. This would provide PG&E with flexibility to execute NPAs whenever
23 feasible and cost-effective without having to attempt to forecast a separate NPA budget.
24 It would also better ensure that all feasible and cost-effective NPAs are deployed to avoid
25 the new long-term investments in fossil fuel infrastructure that would otherwise have
26 occurred.

27 However, to the extent the Commission prefers an approach with a separate NPA budget,
28 the Commission should increase PG&E's \$19.8 million request for AEP projects to \$50
29 million to be used for both AEP and the Service Line NPA program with any unspent
30 funds returned to gas ratepayers. Assuming an average service line NPA incentive of
31 \$17,500, this would fund approximately 1,700 service line NPAs per year and provide
32 overall savings when paired with a mechanism to ensure gas customers benefit from the
33 savings from avoided capital investment in the gas system.

⁶⁶ Attach. 7, Excerpts from State of New York Public Service Commission, *Joint Proposal*, Case 25-E-0072/73, at 24–25 (Nov. 5, 2025)

⁶⁷ See D.23-11-069 at 82, 141, 901.

1 **Q. Please explain the basis for your recommendation that the Commission approve \$3**
2 **million for administrative expenses for AEP and a Service Line NPA and classify**
3 **these costs as an operational expense? (Vespa)**

4 **A.** Three million is an increase from the two million PG&E is requesting for AEP
5 implementation, to reflect additional costs associated with start-up and administration of
6 a Service Line NPA Program. PG&E describes the activities within AEP implementation
7 as including “staffing support for program development and implementation, public
8 induction cooking demonstrations, mailers, and fliers to customers within target zones,
9 creation of AEP-specific marketing materials to share with customers at in-person
10 meetings and other outreach efforts.”⁶⁸ These are activities that can overlap with Service
11 Line NPA marketing and outreach to reduce overall administrative costs from PG&E’s
12 NPA portfolio. However, given that PG&E replaces approximately 14,000 service lines
13 connected to a single residential gas customer each year, even with a standardized offer,
14 additional resources are likely needed to reach this volume of eligible customers, respond
15 to inquiries, and process NPA applications. Three million in costs, with any unspent
16 costs returned to gas ratepayers, can better ensure sufficient funding to support Service
17 Line NPA program administration.

18 In addition, I agree with PG&E’s proposal that implementation costs be treated as
19 operational expenses that are not categorized as regulatory assets with a rate of return.⁶⁹

20 **VII. RECOMMENDATION FOR SERVICE LINE NPA INCENTIVE LEVELS**

21 This section sets forth the underlying data and analysis supporting Sierra Club and
22 NRDC’s recommendation that a Service Line NPA Incentive provide a standardized
23 \$15,000 incentive for gas customers facing a service line replacement and an enhanced
24 \$20,000 incentive for customers in DACs. This incentive level would apply to residential
25 service line replacements under MATs 14A, 14D, 50A, and 50B where the customer has
26 the only meter connected to the service line.

27 **Q. What is the average cost of service line replacement under each of PG&E’s**
28 **programs? (Vespa)**

29 **A.** According to PG&E, for the Reliability Service Replacement Program (MAT 50B), the
30 average cost of service line replacement from 2022–2024 was \$32,651 for residential
31 customers and \$53,222.48 for commercial customers.⁷⁰ For Simple Distribution Service

⁶⁸ Exh. PG&E-03, Errata Testimony at 9-19:27–31.

⁶⁹ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-18, Q.3.

⁷⁰ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.4(b).

1 Replacements (MAT 50G), the average unit cost of service replacement was \$21,512 for
2 residential customers and \$24,900 for commercial customers.⁷¹ PG&E explains the
3 difference in cost between replacing service lines under the Reliability Service
4 Replacement Program (MAT 50B) and Simple Distribution Service Replacements (MAT
5 50G) is attributable to Reliability Service Replacements requiring additional planning and
6 engineering labor.⁷²

7 For service lines replaced in conjunction with distribution mains, PG&E’s cost forecast
8 does not provide the “level of granularity to enable differentiating the replacement costs
9 for mains from the associated services.”⁷³

10 **Q. Based on the data available, what is your estimate of the avoided capital costs from**
11 **deployment of a service line NPA? (Vespa)**

12 **A.** I estimate avoided capital costs of service line replacement are approximately \$16,000 for
13 service line replacements under MAT 50B, 14A, 14D and 50A. The \$16,000 estimate is
14 for upfront capital cost only and does not reflect the NPV lifetime revenue requirement
15 impact of an average service line replacement, which is discussed further below.

16 With regard to the Reliability Service Replacement Program (MAT 50B), PG&E states
17 the average replacement cost for service lines connected to residential customers between
18 2022–2024 was \$32,651.⁷⁴ However, were a customer to electrify and cease gas service
19 in lieu of service line replacement, PG&E would incur additional costs to decommission
20 the service line. Under Utility Procedure TD-9500P-16, Abandonment of Underground
21 Gas Facilities, “[i]f the service is requested to be cut off for demolition and the applicant
22 does not have plans for future reconnection, the Company will treat the service as
23 abandoned and will cut the service off at the main at the Company’s expense.”⁷⁵

24 PG&E did not provide average decommissioning costs for this type of pipeline
25 decommissioning. In response to discovery, PG&E stated that it had data for gas service
26 cut-offs for its Stub Program (MAT 50H), which had a unit cost of \$16,435.⁷⁶ Applying
27 this cost for service line decommissioning would yield an average avoided capital cost of
28 \$16,216 (subtracting decommissioning cost from \$32,651 average pipeline replacement
29 cost for residential Reliability Service Replacements).

⁷¹ Attach. 2, PG&E Supplemental Response to Data Request Sierra Club-PG&E-01, Q.6(b).

⁷² Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-02, Q.3.

⁷³ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.5(c).

⁷⁴ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.4(b).

⁷⁵ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-05, Q.3, Attach. 2, at 5 of 12.

⁷⁶ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-05, Q.3(b).

1 In the case of Simple Distribution Service Replacements (MAT 50G), the average cost of
2 residential service line replacements is \$21,512.⁷⁷ This would leave an average avoided
3 cost of approximately \$5,000 once decommissioning costs are accounted for.⁷⁸

4 PG&E does not currently separate out the specific cost of service line replacements when
5 part of a larger main replacement project.⁷⁹ Accordingly, average replacement cost data
6 for this type of service line replacement is unavailable. I estimate that the average
7 avoided capital costs for Service Line NPAs for these projects is approximately \$16,000.
8 One way to estimate average service line replacement costs for services is to apply a
9 discount to the cost of Simple Distribution Service Replacement to account for the
10 efficiencies that would occur were these service lines replaced as part of a single larger
11 project. The average unit cost of service replacement under the Simple Distribution
12 Service Replacements (MAT 50G) program is \$21,512 for residential customers.⁸⁰
13 Using \$16,000 as the average avoided cost for service line replacement would discount
14 this amount by more than 25 percent to account for the economies of scale of larger
15 projects.

16 Another data point in estimating average cost of service line replacement for distribution
17 main projects is information PG&E provided in the Long-Term Gas Planning Proceeding,
18 R.24-09-012. In response to an ALJ Ruling Directing Gas Utilities to Provide Gas
19 Distribution Cost Data, PG&E identified the average cost of service line replacement as
20 part of distribution main replacement programs as \$33,682 using data from 2021–2024.⁸¹
21 However, this amount includes a portion of the replacement costs for the distribution
22 main itself.⁸² Using \$16,000 as the average avoided cost for the replacement cost of only
23 the service lines would be more than a 50 percent discount from costs that include a
24 portion of main replacement costs.

25 While decommissioning costs are a significant factor in assessing the avoided cost for
26 service-line only replacement programs, there would not be significant added costs from
27 service line decommissioning where the service line is being decommissioned as part of a
28 larger pipeline replacement project since PG&E would already be excavating and
29 installing a replacement main, only with fewer service line connections. For this reason,

⁷⁷ Attach. 2, PG&E Supplemental Response to Data Request Sierra Club-PG&E-01, Q.6(b).

⁷⁸ Because of the lower avoided CapEx from service replacement under this program, I do not recommend these replacements be initially included in the Service Line NPA Program.

⁷⁹ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.5(c).

⁸⁰ Attach. 2, PG&E Supplemental Response to Data Request Sierra Club-PG&E-01, Q.6(b).

⁸¹ R.24-09-012, PG&E's Response to ALJ's Ruling Directing Gas Utilities to Provide Gas Distribution Cost Data (Nov. 5, 2025), Attach. A-1, Row ID A1,

<https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M586/K273/586273755.PDF>.

⁸² Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-10, Q.3.

1 I do not include decommissioning costs in determining the avoided capital costs for a
2 Service Line NPA where the main attached to the service line will be replaced as part of
3 the project.

4 In addition, the \$16,000 estimate for average avoided cost of service line replacements is
5 conservative in that it is based off historic costs and does not account for escalation in
6 service line replacement costs.

7 **Q. How should the Commission determine the avoided cost of service line replacement?**
8 **(Velez)**

9 **A.** Like PG&E’s assessment of NPAs for AEP, PG&E should evaluate alternatives on a
10 NPV basis.⁸³ NPV is a commonly accepted method of comparing the lifetime cost of a
11 gas investment to an alternative by assessing the lifetime revenue requirement impacts of
12 the two investments and then converting the lifetime cost savings to a present value. In
13 other words, one can calculate the lifetime cost to utility customers of either
14 investment—including any rate of return and taxes collected from customers—and then
15 convert the lifetime cost savings from future dollar savings to present dollars in a manner
16 that accounts for the “time value of money” to utility customers. “Time value of money”
17 refers to the principle that a dollar today is worth more than a dollar in the future.

18 For example, as set forth in Table 2 in Section IV above, a gas investment with an
19 upfront capital cost of \$1 million that is collected over 55 years would cost PG&E
20 customers \$3.78 million (nominal dollars, \$_{nom}) over the lifetime of the investment,
21 when considering the utility rate of return and taxes collected from customers.⁸⁴
22 Converting to NPV, the total lifetime cost of the investment would be \$1.24 million
23 dollars (NPV), despite having an upfront capital cost of only \$1 million.⁸⁵ This means
24 that, for a \$1 million gas investment, gas utility customers actually pay an additional

⁸³ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.17. To calculate NPV, PG&E considers the study period, discount rate, project installation year, project costs and their investment type (capital or expense), cost escalation rate, asset lifespan, and associated operating expenses and revenues. Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-05, Q.6.

⁸⁴ I produced these values by inputting the aforementioned project cost and number of projects into my NPA Cost Analysis Tool, provided as Attachment 6 and setting the NPA project values to zero, to isolate the impacts of the gas investment. “Avoided Return on Investment” for the gas investment is provided on the YOY Revenue Requirement tab, Cell X5. Other referenced outputs are provided on the Dashboard tab. My complete methodology for the NPA Cost Analysis Tool is provided in Attachment 5.

⁸⁵ To calculate the NPV, it is necessary to assume a “discount rate” that reflects the time value of money from the perspective of gas utility customers. Unless otherwise specified, NPV is calculated throughout this testimony using a discount rate of 5 percent to represent the utility customer’s perspective, as discussed further in Section 5.1 of the NPA Cost Analysis Tool Methodology Document (Attachment 5)

1 \$1.78 million (\$nom) (or an additional \$240,000, in NPV) in taxes and utility return on
2 investment over its lifetime.

3 Conversely, spending \$1 million on a NPA that is depreciated over 10 years, instead of
4 55 years, would cost \$1.46 million (\$nom) over its lifetime, including utility returns and
5 taxes. Because gas customers would pay the utility a return on the investment over a
6 much shorter time period, investing \$1 million in an NPA depreciated over 10 years
7 instead of a gas replacement would save customers more than \$2.3 million (\$nom) over
8 the investment lifetime. This translates to more than \$200,000 in customer savings in
9 NPV terms.

10 While not a perfect analogy, one can compare utility profits to compounding interest
11 payments on a loan: the longer one takes to pay off a loan, the more interest accumulates,
12 thus increasing the total cost of the loan to the customer. Investing in a 10-year NPA
13 versus a 55-year gas investment significantly reduces the amount that utility customers
14 must pay in “interest” over the lifetime of the investment.

15 **Q. How did you calculate the NPV of a Service Line NPA? (Velez)**

16 A. To evaluate the NPV savings of investing in an NPA rather than a planned gas
17 investment, I used my NPA Cost Analysis Tool (“Tool”): an Excel spreadsheet model I
18 developed to enable users to compare the annual revenue requirement and rate impacts of
19 an NPA portfolio with a gas investment that would otherwise take place. The modeling
20 assumes that gas ratepayers either pay for a planned gas investment or an NPA. The Tool
21 also estimates the emissions impacts and associated societal costs of the NPA portfolio. I
22 describe my methodology and sources in detail in Attachment 5.

23 Notably, my model assumes that all modeled investments take place in the same year.
24 For that reason, I only present the impact of Year 1 of my proposed Service Line NPA
25 Program in this testimony, in order to reflect NPV costs as accurately as possible. The
26 Tool is available as executable Attachment 6, and users can easily run scenarios in the
27 *Dashboard* tab using their own inputs.

28 My modeling finds that PG&E could offer customers an average Service Line NPA
29 Program incentive of up to approximately \$20,390 while still ensuring that the program
30 “breaks even” from a NPV cost perspective with the gas service line replacements that
31 would otherwise occur. However, to optimize near- and long-term affordability
32 considerations while also delivering on climate and equity objectives, my
33 “Recommended Scenario” is for the Commission to approve a Service Line NPA
34 Program that provides a base incentive of \$15,000 and an enhanced incentive of \$20,000
35 for customers in DACs. This incentive level would apply to eligible households facing a
36 planned gas service line replacement under MATs 14A, 14D, 50A, and 50B and where

1 the customer has the only meter connected to the service line. I assume that 50 percent of
2 program participants reside in a DAC, resulting in a weighted average incentive amount
3 of \$17,500 per participating household.

4 **Q. Please briefly summarize the results of your modeling with the NPA Cost Analysis**
5 **Tool. (Velez)**

6 **A.** My modeling finds that an equity-focused Service Line NPA Program that delivers 1,000
7 building electrification incentives at an average cost of \$17,500 per incentive would yield
8 the following impacts in Year 1:

- 9 • Lifetime gas system savings of approximately \$44 million (\$nom), or about \$20
10 million in 2025 dollars,
- 11 • NPV savings of approximately \$3 million,
- 12 • NPV Social Cost Savings of approximately \$7.9 million due to avoided carbon and
13 methane emissions, and
- 14 • A Non-Participant Gas Bill Impact of merely 22 cents for the entire first year of the
15 program. In every future year, the bill and rate impact of the Service Line NPA
16 Program would decline, until reaching zero by Year 10; while the counterfactual gas
17 service line replacement would be paid off by customers over 55 years.

18 Across all sensitivities modeled, including a “Pessimistic Scenario,” the Service Line
19 NPA Program delivers robust customer benefits.

20 **Q. Please describe the Recommended Scenario that you modeled. (Velez)**

21 In the “Recommended Scenario” model run, I assume the following:

22 **Table 3: Recommended Scenario Model Inputs**

Key Input	Value	Description
Number of NPA Projects	1000 projects	I assume that the Service Line NPA Program electrifies 1000 households in Year 1, which is 2.25 percent of PG&E’s estimated gas service line replacements between 2022–24. ⁸⁶
Gas – CapEx per Service Line	\$16,000	I assume an average gas service line replacement cost of \$16,000, as discussed in Section V.B.

⁸⁶ This percentage is calculated as $[(1000 / (6,106 + 35,827 + 2,563)) * 100]$. Service replacements between 2022–24 are provided in Table 3 above.

Gas – Annual O&M per Service Line	\$83 per year	PG&E reports that \$83 per year per line is their average cost to operate and maintain a gas service line. ⁸⁷
Gas – Depreciation Period	55 years	PG&E’s gas asset lifetimes range from 55–68 years. I assume that gas service line asset life falls at the lowest end of this range, which is a conservative assumption. ⁸⁸
NPA – CapEx per Project	\$17,500	I assume a Service Line NPA Program that provides an equity-focused electrification incentive of \$20,000 to customers who reside in a DAC and a market-rate incentive of \$15,000, with a 50-50 split in uptake between equity and market-rate customers. I assume that the incentives deployed are recovered as a gas regulatory asset (“CapEx”).
NPA – OpEx per Project	\$200	I assume NPA administrative costs are collected as operational costs (“OpEx”). The administrative cost assumed is reflective of the simple, streamlined nature of this incentive program, which can take advantage of existing channels of communication with customers who are facing a planned service replacement and existing program infrastructure, such as that developed for AEP and the SB 1221 pilot program. Administrative costs are assumed to be recovered through in Year 1 and are not afforded a rate of return.
NPA – Depreciation Period	10 years	I assume NPA incentives are treated as a regulatory asset and depreciated over 10 years, which strikes the best balance between near- and long-term affordability considerations among the sensitivities I ran.
Customer-Perspective Real Discount Rate	5%	My Recommended Scenario assumes a customer-perspective real discount rate of 5%, as discussed in Attachment 5, Section 5.1. The customer-perspective real discount rate is adjusted for inflation within the model to provide a nominal discount rate, which is applied to the series of annual revenue requirement savings (presented in nominal dollars) to calculate the NPV of the lifetime cost savings of the Service Line NPA Program.

⁸⁷ R.24-09-012, PG&E Maintenance Data Costs Template, as provided by utilities to the R.24-09-012 service list on November 5, 2025, Distribution Pipelines Tab, Row ID G1, <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/sb1221/data/pge/maintenance-costs--pge.xlsx>.

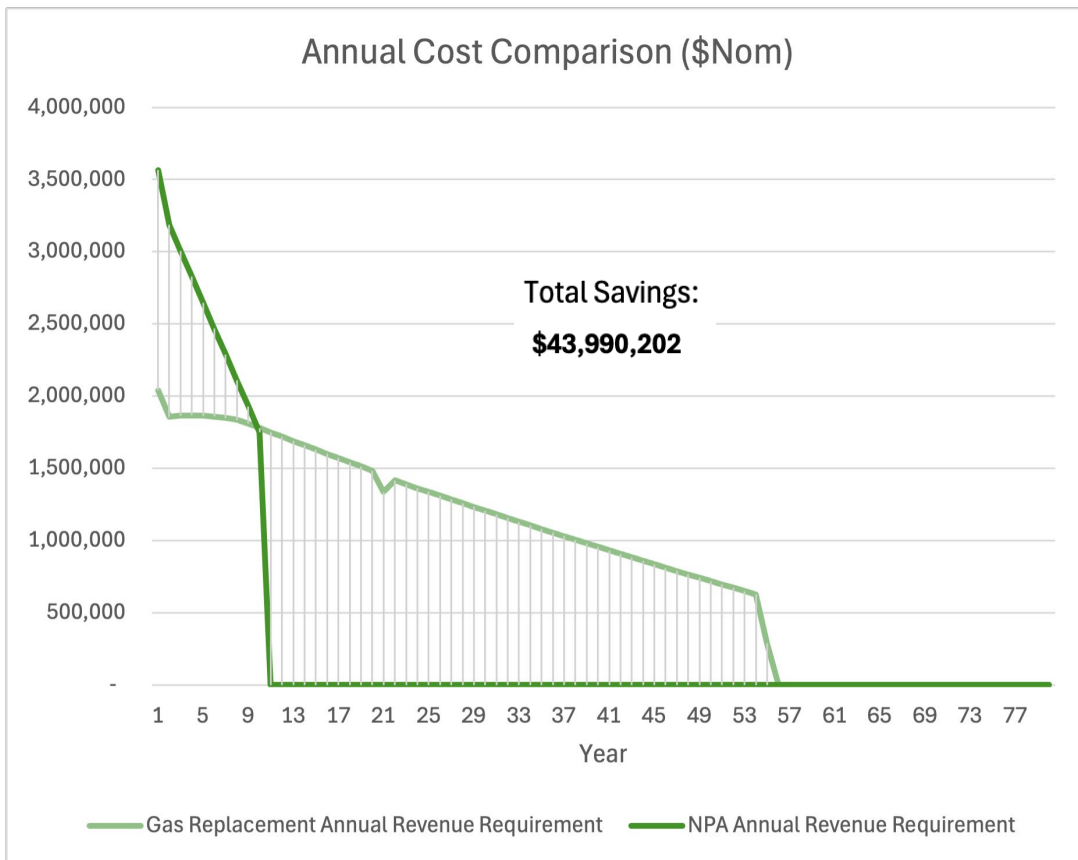
⁸⁸ Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.19; PG&E Response to Data Request Sierra Club-PG&E-06, Q.1(d).

1 The model requires numerous other utility-specific inputs to generate results. These
2 inputs are primarily drawn from discovery responses in this proceeding and other
3 publicly available datasets. I list each detailed modeling input and my sources in
4 Attachment 5, Section 5: “Default Inputs and Data Sources for PG&E Analysis” and in
5 the *Data and Sources* tab of my NPA Cost Analysis Tool.

6 **Q. What are the lifetime gas revenue requirement savings of your Recommended**
7 **Scenario for the Service Line NPA Program? (Velez)**

8 **A.** Assuming 1000 participants, Year 1 of the Service Line NPA Program results in cost
9 savings of approximately **\$44 million** (\$Nom) for utility customers in the Recommended
10 Scenario. It yields the following year-over-year revenue requirement impacts:

11 **Figure 2: Annual Cost Comparison (\$Nom), Gas Replacement vs. Service Line NPA**
12 **Program**



13
14 As demonstrated in the figure above, the Service Line NPA Program yields significant
15 lifetime savings—one can interpret the net area between the curves (indicated with gray
16 stripes) as representing the lifetime cost savings of the Service Line NPA projects (“NPA

1 Annual Revenue Requirement”) versus the otherwise-planned gas service replacements
2 (“Gas Replacement Annual Revenue Requirement”). The NPA projects significantly
3 reduce stranded cost risk, since the NPA investment is paid off by ratepayers over 10
4 years, as compared to the assumed 55-year depreciation life of the counterfactual gas
5 service line replacements.

6 As shown in the summary of key cost outputs below, an important source of savings in
7 the NPA Case is the avoided return on investment compared to the Gas Replacement
8 Case. This is largely attributable to the difference in depreciation life between the two
9 investments: The Company collects less return over time from gas ratepayers in the NPA
10 case because the investment is paid off more quickly (10 years versus 55 years), and also
11 because customers avoid the lifetime costs of operating and maintaining the gas service
12 lines that would otherwise be replaced. **In all, the Service Line NPA Program delivers**
13 **NPV savings of \$3 million to gas customers in the Recommended Scenario.**

14 **Figure 3: Key Cost Outputs, Gas Replacement vs. Service Line NPA Program in**
15 **Recommended Scenario⁸⁹**

Key Cost Outputs	
Total Cost, Gas Replacement (\$Nom)	\$ 69.8 M
Total Cost, NPA (\$Nom)	\$ 25.8 M
Total Savings (\$Nom)	\$ 44.0 M
Total Savings (\$2025)	\$ 20.0 M
Avoided Return on Investment (\$Nom)	\$ 36.4 M
Total Savings (NPV)	\$ 3.0 M

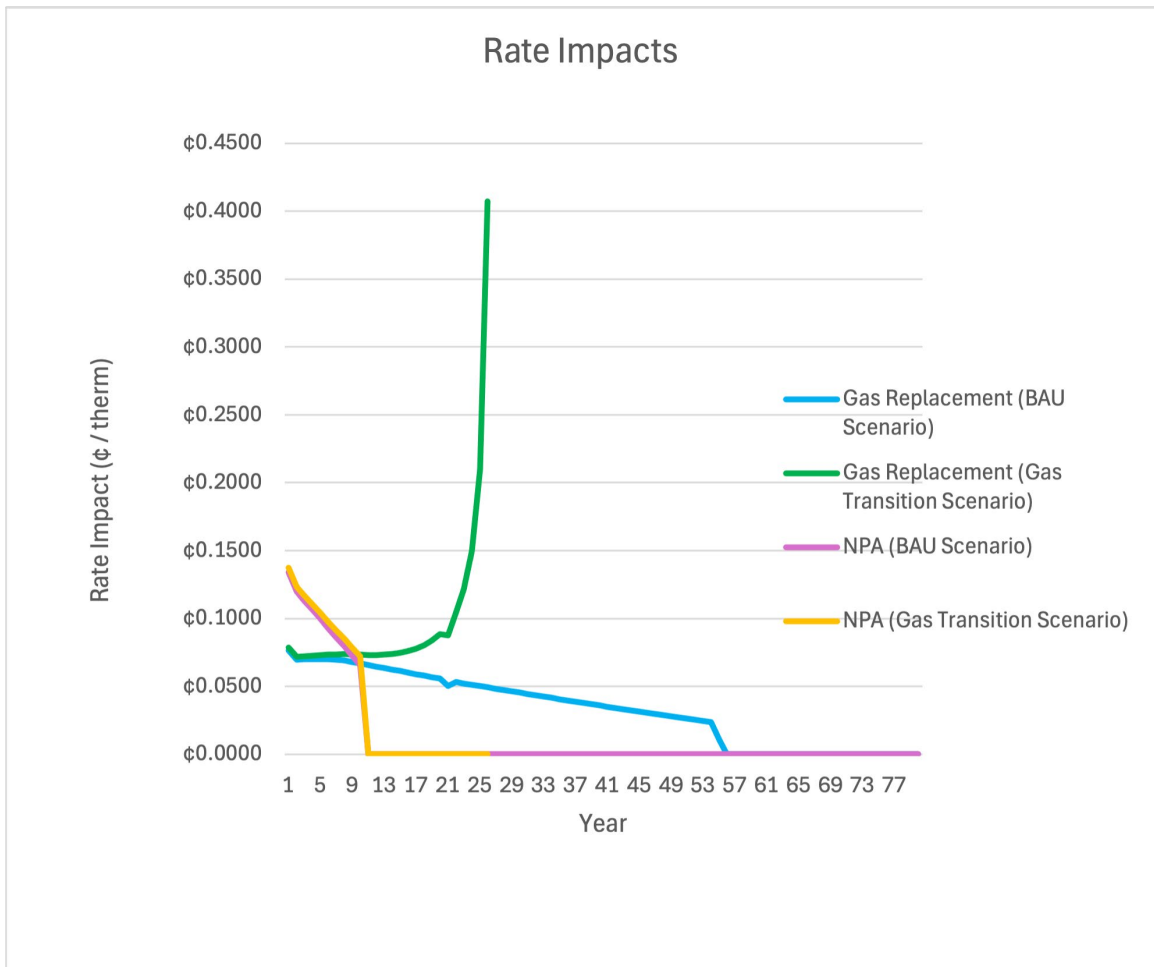
16
17 **Q. What is the gas rate impact of your recommended Service Line NPA Program?**
18 **(Velez)**

19 **A.** To evaluate the long-term rate impacts of adopting the NPA program, I considered two
20 background gas throughput scenarios: 1) a Gas Transition Scenario that assumes PG&E’s
21 core customer gas throughput declines by 88 percent by 2050, consistent with PG&E’s
22 “GT AAFS 2.5 Demand, Flat RR Scenario” from the 2025 IEPR discussed in Section III
23 and 2) a Business-as-Usual Scenario in which electrification does not substantially
24 increase in the future. The Service Line NPA Program yields significant long-term rate

⁸⁹ Attach. 6, NPA Cost Analysis Tool, Scenario Runs tab.

1 benefits in both scenarios, but the Gas Transition Scenario highlights the affordability
 2 benefits of investing in shorter-lived NPA assets rather than re-investing in long-lived gas
 3 assets as California transitions away from gas. Notably, for the NPA Case, I assume that
 4 the 1,000 households that participate in the Service Line NPA Program depart the gas
 5 system, thus slightly reducing annual gas throughput and customer count. The results of
 6 these scenario runs for both the Gas Replacement Case and the NPA Case are presented
 7 in the figure below:

8 **Figure 4: Rate Impacts, Gas Replacement vs. Service Line NPA Program**



9
 10 In the graph above, rate impacts are presented in cents, reflecting the negligible near-term
 11 rate impact of the Service Line NPA Program. While the recommended Program
 12 increases rates in Year 1 compared to gas replacement (because NPA costs are collected
 13 on a shorter time frame and include Year 1-only administrative costs), the increase is
 14 miniscule. A non-participating gas customer would pay **only about 22 cents extra** on
 15 their annual gas bill over the entirety of Year 1 to fund the program, and the bill impact

1 would decline every year until the NPA investment is paid off in Year 10. Conversely,
2 under the Gas Transition scenario, the rate impact of the counterfactual gas service line
3 replacements increases significantly over time, as households depart the gas system in
4 line with California’s pressing climate goals.

5 **Q. Does a Service Line NPA Program provide NPV cost savings under other modeling**
6 **assumptions? (Velez)**

7 **A.** Yes. To understand how the cost-effectiveness of the proposed Service Line NPA
8 Program would vary under different program design and cost inclusion assumptions, I
9 modeled numerous alternative scenarios. Each maintains most of the inputs from the
10 Recommended Scenario, with any modifications described below. The alternative
11 scenarios that I modeled fall under five main categories:

- 12 1. **Different Incentive Amounts:** I modeled a Lower Incentive scenario (average incentive
13 level set to \$16,000); a Higher Incentive scenario (average incentive level set to
14 \$20,000); and a Max Incentive scenario (average incentive level set to \$20,391, which
15 results in zero NPV savings). A key finding from these runs is that a program with an
16 average incentive of \$20,000 would still deliver about \$400,000 in NPV savings to gas
17 customers, while having a Year 1 Non-Participant Bill Impact of only 29 cents for the
18 entire first year of the program.
- 19 2. **Different Discount Rates:** I modeled a Lower Discount Rate scenario (customer-
20 perspective, real discount rate set to 2.5 percent to align with the Social Discount Rate)
21 and a Higher Discount Rate scenario (rate set to 7.2 percent, which is PG&E’s Weighted
22 Average Cost of Capital (“WACC”). Even assuming a very high discount rate of 7.2
23 percent, the program delivers nearly half a million dollars in NPV savings. With a lower
24 discount rate, the program delivers more than \$8 million in NPV savings.
- 25 3. **Different NPA Cost Recovery:** I modeled a No NPA Regulatory Asset Treatment
26 scenario (NPA costs are recovered as OpEx in Year 1) and a 15-Year NPA Depreciation
27 scenario (NPA costs are recovered over 15 years as CapEx). I find that the
28 Recommended Scenario’s 10-year cost recovery is significantly more favorable than
29 either of these alternatives from an affordability perspective. The 15-Year NPA
30 Depreciation scenario reduces lifetime NPV savings by about \$1 million due to increased
31 utility return on investment; while the No NPA Regulatory Asset Treatment scenario
32 increases the Year 1 Non-Participant Bill Impact tenfold compared to my Recommend
33 Scenario.
- 34 4. **Higher Program Participation:** I modeled a scenario in which the program reaches
35 5,000 households, rather than 1,000. This scenario demonstrates that the Program’s
36 affordability and climate benefits simply scale with greater participation—this scenario

1 results in NPV cost savings of \$15 million and NPV emissions cost savings of \$39
2 million, as compared to \$3 million and \$7.9 million respectively in the Recommended
3 Scenario. Higher program participation means more program benefits, while the Year 1
4 Non-Participant bill impact is still minimal (about \$1.10 annual bill increase for all of
5 Year 1).

- 6 5. **Pessimistic Scenario:** This represents a “worst case” scenario, in which the avoided gas
7 replacement cost is lower than expected (\$15,000, rather than \$16,000), NPA
8 administrative costs per project are higher than expected (\$500, rather than \$200), and a
9 higher real discount rate is assumed for NPV calculations (6 percent, rather than 5
10 percent). Nevertheless, this scenario still results in more than \$280,000 NPV savings for
11 gas customers, with a Year 1 Non-Participant Bill Impact of merely 28 cents for the
12 whole year.

13 The results of the alternative scenarios illustrate how our recommended Service Line
14 NPA Program can deliver significant gas customer benefits under a wide range of
15 potential conditions. Moreover, they support the finding that our Recommended
16 Scenario offers the Commission a program design and cost recovery structure that
17 optimizes near- and long-term affordability considerations. Complete assumptions and
18 results for each of these scenarios are provided in the *Scenario Runs* tab of my NPA Cost
19 Analysis Tool, and the Tool can easily be updated to test alternative assumptions per the
20 instructions in the spreadsheet and the accompanying methodology document.

21 **Q. Are there other social benefits of the Service Line NPA Program that are not**
22 **quantified above? (Velez)**

- 23 **A.** Yes. Under the Recommended Scenario, Year 1 of the Service Line NPA Program
24 would reduce annual carbon dioxide emissions by about 2,000 metric tons per year and
25 would reduce annual methane emissions by about 14.6 metric tons per year, resulting in
26 **NPV social cost savings of about \$7.87 million.** I describe the methodology behind my
27 emissions and social cost calculations in detail in Attachment 5, Section 4. Moreover,
28 reducing gas combustion results in health benefits that I did not quantify in my modeling.

29 **VIII. OTHER SERVICE LINE NPA PROGRAM RECOMMENDATIONS (VESPA)**

30 This section identifies additional elements of a Service Line NPA Program, with a
31 particular focus on implementation aspects that may differ from New York’s program.

1 **Q. What service line replacements should be eligible for the proposed Service Line**
2 **NPA Program?**

3 **A.** I recommend PG&E be directed to offer the Service Line NPA program for residential
4 customers facing a replacement under MAT codes 50B (Reliability Service Replacement
5 Program), 14A (Gas Pipeline Replacement Program), 14D (Plastic Pipe Replacement
6 Program) and 50A (Reliability Pipe Replacement Program). As set forth above, these
7 programs have approximately the same avoided CapEx per service line for residential
8 customers, which enables a standardized incentive across programs. In addition, average
9 costs of service line replacements for commercial customers appear to be significantly
10 higher than for residential customers.⁹⁰ Leaving these types of replacements within AEP
11 would allow for customized and potentially higher incentives that depend on the specifics
12 of individual service line replacement.

13 **Q. What are other elements of a Service Line NPA Program?**

14 **A.** Program implementation elements should be similar Con Edison's Service Line NPA
15 Program with elements and include:

- 16 • A means for gas customers to verify their eligibility for the Program, such as
17 through an email inquiry to a designated representative or an online look-up tool;
- 18 • Customer outreach, with additional outreach provided to customers in DACs, that
19 includes information on the air quality and health benefits of electrification;
- 20 • A list of potential contractors;
- 21 • Review to ensure that, where necessary, in-front-of-meter electrical upgrades
22 occur prior to project execution;
- 23 • A requirement for gas disconnection and gas meter removal as a condition of
24 program participation; and
- 25 • Follow up surveys to enable incorporation of customer feedback to program
26 design updates.

27 For purposes of approval as part of a decision on PG&E's GRC Application, the
28 Commission could set higher-level program guidance and leave PG&E to develop
29 specific implementation details.

⁹⁰ See, e.g., Attach. 2, PG&E Response to Data Request Sierra Club-PG&E-01, Q.4(b).

1 **Q. Are there California-specific factors that should inform how PG&E engages with**
2 **eligible customers?**

3 **A.** Yes. The Service Line NPA Program should be viewed as part of a suite of NPA
4 offerings, including SB 1221 projects and AEP, and where applicable, leverage the same
5 partner and community relationships. In designating Priority Neighborhood
6 Decarbonization Zones, the Commission identified local governments and other entities
7 that demonstrated community interest in decarbonization projects in their region.⁹¹
8 PG&E should notify these entities of planned service line replacements to enable
9 additional outreach from local partners.

10 Similar to Con Edison, PG&E should also set up a dedicated webpage that explains the
11 program, has a contractor look-up tool, and has a means for interested customers to
12 determine their eligibility, such as through an e-mail inquiry to a designated utility
13 representative.⁹²

14 **Q. Should PG&E’s process for determining the need for panel and service line**
15 **upgrades differ from Con Edison’s approach?**

16 **A.** Yes. One measure not explicitly included in Con Edison’s Service Line NPA program
17 that the Commission could incorporate is efforts to avoid an electric service line upgrade
18 where feasible. In the Building Decarbonization proceeding, the Commission found in
19 D.25-06-034 that “service upsizing can be a costly and time-consuming process for
20 customers and utilities” and directed “all electric utilities to engage with service upsizing
21 applicants about alternatives to service upsizing prior to any application submission.”⁹³
22 The Commission similarly acknowledged “the benefit of ensuring customers and
23 contractors are fully aware of alternatives to panel upsizing.”⁹⁴ If a home assessment
24 indicates a panel upgrade may be needed, PG&E should ensure both customers and
25 Participating Contractors are aware of and have considered alternatives such as circuit
26 sharing or other devices that avoid electrical upgrades.

⁹¹ See D.25-12-042, *Decision Designating Initial Priority Neighborhood Decarbonization Zones*,
Appendix A (Dec. 23, 2025),

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M592/K318/592318695.pdf>.

⁹² See Con Edison, *Energy Exchange Program*, *supra* note 46.

⁹³ D.25-06-034, *Phase 4 Track A Decision Establishing New Electric Service Line Upsizing Rules, Modifying Electric Line Extension Rules and Reporting Requirements, and Implementing Assembly Bill 157*, at 60, 62 (June 20, 2025),

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M570/K302/570302781.PDF>.

⁹⁴ *Id.* at 60.

1 **Q. What steps should PG&E take to increase deployment of Service Line NPAs in**
2 **Environmental and Social Justice (“ESJ”) Communities?**

3 **A.** Like the Con Edison program, our recommended proposal offers an enhanced incentive
4 for customers located in a DAC. Like the Con Edison program, PG&E can also focus
5 targeted outreach, such as site visits and phone calls, on customers in ESJ communities,
6 with wider-reaching marketing methods, such as email and mailers, extended to larger
7 populations of eligible customers.⁹⁵ However, our \$20,000 proposed incentive for DAC
8 customers is unlikely to cover the full cost of home electrification, particularly where
9 electrification would include replacement of multiple gas appliances, electric work and
10 remediation. Accordingly, PG&E should coordinate with program administrators of low-
11 income ratepayer and non-ratepayer funded efficiency and electrification programs to
12 maximize incentive layering. For example, the Equitable Building Decarbonization
13 (“EBD”) program “provides and installs energy-efficient electric appliances, energy
14 efficiency measures, and related upgrades at no cost to low-income households in under-
15 resourced communities.”⁹⁶ Coordination with regional EBD administrators can provide
16 an additional source of funding to support Service Line NPA deployment for low-income
17 households while also helping limited EBD funding reach more households by taking
18 advantage of Service Line NPA opportunities.

19 **Q. What are your recommendations on AEP and Service Line NPA Program**
20 **Reporting?**

21 **A.** I recommend PG&E’s existing annual reporting on AEP include additional information
22 on AEP projects and be combined with reporting on the Service Line NPA Program.
23 PG&E’s current AEP annual reports leave out information necessary to understand
24 program benefits and implementation. For example, while the AEP 2024 Annual Report
25 identifies the total number of residential and commercial meter conversions and reasons
26 conversions did not occur, it omits basic information on specific projects such as the
27 MAT code of the gas investment the project avoided and number of meter conversions
28 per project.⁹⁷ For each avoided gas infrastructure project, AEP reporting should include:
29

- The specific infrastructure avoided and its MAT code(s);

⁹⁵ See Attach. 4, Con Edison, *Non-Pipes Alternatives Implementation Plan*, *supra* note 46, at 16.

⁹⁶ CEC, *EBD Statewide Direct Install Program*, <https://www.energy.ca.gov/programs-and-topics/programs/equitable-building-decarbonization-program/ebd-statewide-direct> (last visited Feb. 6, 2026).

⁹⁷ Attach. 3, PG&E AEP 2024 Annual Report.

- 1 • The number of meter conversions that occurred as part of the project by
2 customer class;
3 • Ratepayer savings from project implementation.

4 With regard to implementation of the Service Line NPA Program, helpful information
5 would include the number of incentives offered and the number accepted within and
6 outside of DACs.

7 **Q. Does this conclude your testimony?**

8 **A. Yes.**

ATTACHMENT LIST

Attachment

- 1 **Witness Qualifications**
- 2 **Complied PG&E Responses to Sierra Club Data Requests Cited in Testimony**
- 3 **PG&E, 2024 Alternative Energy Program Annual Report**
- 4 **Consolidated Edison, Non-Pipes Alternatives Implementation Plan (Nov. 2024)**
- 5 **Danielle Velez, NRDC, “Service Line NPA Cost Analysis Tool” Methodology Paper**
- 6 **NRDC, Service Line NPA Cost Analysis Tool (Executable Excel File)**
- 7 **Excerpts from State of New York Public Service Commission, *Joint Proposal*, Case 25-E-0072/73 (Nov. 5, 2025).**