Evaluating the funding opportunity for energy efficiency and electrification from non-pipeline alternatives

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ABSTRACT

Non-pipeline alternatives (NPAs) are projects that avoid gas infrastructure investments and/or retire existing gas infrastructure through measures that reduce gas usage. NPAs have emerged as a potential strategy to reduce gas system costs, particularly if significant levels of building electrification requires the recovery of fixed gas system costs over fewer customers. Portions of the avoided costs from NPAs can be reallocated to pay for electrification or energy efficiency measures.

From our projects, we define two categories of NPA opportunities, "Zero Gas" NPAs and "Demand Reduction" NPAs, each with distinct planning requirements, measures, and implementation strategies. Zero Gas NPAs focus on completely eliminating gas service within small areas such as blocks or neighborhoods, avoiding gas mains and services, and rely on full electrification, networked geothermal, and delivered fuels. Demand Reduction NPAs, by contrast, aim to lower peak gas demand to avoid or defer large peak-driven infrastructure investments across broader areas. They use a wider set of measures, including energy efficiency upgrades, demand response, electrification, and alternative fuels. Challenges differ: Zero Gas NPAs need full customer participation, while Demand Reduction NPAs require consistent demand reductions despite growth trends.

We develop this dichotomy and share relevant case studies, illustrating the benefits and challenges for each type as well as the role of energy efficiency and electrification measures.

Introduction

As states, cities, and utilities plan to meet decarbonization goals, electrification has emerged as a key strategy to reduce emissions from fuel combustion in buildings. However, widespread building electrification would pose a challenge for cost recovery on the gas system as fixed gas system costs are spread among fewer customers (ref MA, PGW, California). Under existing rate and cost recovery paradigms, this would lead to significant increases in customer rates for remaining customers, who may disproportionately be households least able to electrify like low income customers and renters. Avoiding gas system investments will then be crucial to limit rate impacts on remaining gas customers. NPAs are projects that avoid gas infrastructure investments and/or retire existing gas infrastructure through measures that reduce or eliminate gas usage. Portions of these avoided costs can be reallocated to pay for electrification or energy efficiency measures (ref CEC).

NPAs by state

Due to their potential benefits, several states have developed new policies in an attempt to facilitate NPA deployment. Table 1 summarizes key features of these policies by state, which often tie utility spending prudence review to conducting an NPA evaluation or focus on utilities bringing forward pilot projects. These requirements differ by jurisdiction, with key differences including:

- Dollar thresholds when evaluating NPAs is required
- Mechanism triggering regulator review of the NPA evaluation (e.g. planning docket vs. prudence review)[1]
- Enabling policy changes to facilitate NPA implementation (e.g. California's limited change to the obligation to serve[2] on a pilot basis)

Table 1. NPA requirements by state

State	Status of NPA Proceedings
California	In 2020, the California Public Utility Commission (PUC) ruled that gas utilities are required to evaluate NPAs for large transmission-level investments (>$75M) and identified NPAs as a potential strategy to avoid repairing and replacing gas distribution infrastructure. In 2024, Senate Bill 1221 was passed, requiring the California PUC to designate priority neighborhood decarbonization zones and enabling up to 30 pilot decarbonization projects to advance in these zones. It also provided an exception to the utility's obligation to serve, requiring only two-thirds customer opt-in rather than 100% to proceed with the project for all affected customers.
Colorado	In 2021, the Colorado PUC directed gas utilities to evaluate NPAs in their Gas Infrastructure Plans. In 2024, the Colorado PUC provided additional guidance, ordering the Public Service Company of Colorado to evaluate NPAs for all new business, capacity expansion, and safety and integrity projects in future plans.
Maryland	Maryland's 2025 Next Generation Energy Act requires gas utilities to justify new infrastructure investments by evaluating cost-effective alternatives, effectively embedding NPA considerations into project approval and cost recovery. This statutory direction is now being implemented and further defined through the Public Service Commission's (PSC) ongoing "Future of Gas" proceeding (Case No. 9707, Phase II). As of June 2026, this docket is ongoing.

[1] A planning docket is a formal proceeding before a regulatory commission that evaluates forward looking long-term system planning. Prudence review is a retrospective evaluation by the regulator that utility's past expenditures were reasonable at the time they were made.
[2] A utility's obligation to serve is currently typically interpreted to mean that utilities must serve all customers who request service.

Massachusetts	In 2024, the Massachusetts Department of Public Utilities (DPU) ruled that gas utilities are required to consider NPAs for all projects under a prudent investment standard. The DPU also required the gas utilities to conduct a stakeholder process to develop an NPA evaluation framework. In May 2025, the gas utilities filed their framework and they're still under consideration.
New York	The New York PSC (2022) required LDCs to consider NPAs in a "no-infrastructure option" of their Long-Term Plans and to annually identify whether NPAs could substitute for leak-prone pipeline replacement, subject to a minimum project cost threshold. In 2024, the NY PSC developed questions and requested stakeholder responses for NPA framework development.
Rhode Island	In 2020, the Rhode Island PUC established a 3-year System Reliability Procurement Plan (SRP) reporting requirement for Rhode Island Energy, which then identified NPA suitability criteria and a planning process in its 2022 SRP. Rhode Island Energy (2024) published a Decarbonization Framework that aims to develop targeted electrification pilot projects that are technically feasible from a gas and electric system standpoint.
Washington	Large combined gas and electric utilities must develop an integrated system plan that evaluates non-pipeline alternatives for all known and planned gas infrastructure projects, including geographically targeted electrification and demand response, as well as achieving all cost-effective electrification of end uses currently served by natural gas (HB 1159).

Identification of NPA archetypes

E3 has performed several NPA assessments in leading states. From this work, we've identified two NPA project archetypes: Zero Gas and Demand Reduction, as shown in Table 2.

Table 2. NPA Project Archetypes

	Zero Gas NPAs	**Demand Reduction NPAs**
Success Threshold	Termination of gas service for all customers in project area	Peak demand reduction to avoid or defer capacity upgrades, or retire peaking assets
Infrastructure Avoided	Replacement or new construction of gas mains and services that deliver gas to end use customers; larger share of utility rate base *High avoidable costs per customer*	Larger capacity investments; i.e., projects to meet peak gas demand and address supply constraints *Lower avoidable costs per customer*
Geographic Scope	Smaller: city block, set of blocks, or small neighborhoods	Larger: neighborhood, city, or even larger area
Key Measures	Gas elimination measures: E.g. building electrification, networked geothermal, and delivered fuels (e.g., propane)	Gas elimination + reduction measures E.g., shell improvements, efficient gas equipment, electrification,

		demand response / interruptible tariffs[3]
Customer Participation	*Requires full customer opt-in* or utility flexibility to retire gas service	*Requires ambitious, but not total customer opt-in;* must overcome growth trends in some areas.

The remainder of this paper will focus on the evaluation of two NPA evaluations we have conducted. The first is an evaluation of targeted electrification in California for the California Energy Commission (E3 2023), an example of the most commonly discussed type of Zero Gas NPA. The second is an evaluation of a Demand Reduction NPA to eliminate a liquefied natural gas (LNG) peaking facility for Rhode Island Energy (Aas and Gresham 2025). We also summarize examples of NPA analyses conducted by third parties to illustrate some emerging findings.

Examples of NPA Evaluations across Gas Infrastructure Project Types

The examples shown below reflect the opportunities and challenges associated with Zero Gas NPAs and Demand Reduction NPAs. These case studies used real-world utility costs and customer data to assess the avoidable infrastructure costs associated with pipeline replacements, estimate the utility costs associated with deploying NPA measures at scale, and identify key implementation barriers to achieving successful NPA deployment. While the cost-effectiveness of NPAs will vary from project to project depending on key factors such as customer density and avoidable infrastructure replacement costs, these project examples help crystallize potential approaches to appropriately assess and identify NPA opportunities.

Targeted Electrification, California

In 2023, E3 supported the CEC in evaluating the cost-effectiveness of targeted electrification and gas system decommissioning for eleven sites in the San Francisco Bay Area (E3 2023). Working with Ava Community Energy, a community choice aggregator in Alameda and San Joaquin counties, E3 assessed the benefits and costs of targeted electrification for these sites across total cost, electric ratepayer, gas ratepayer perspectives. The study found that avoided gas utility[4] pipeline replacements could yield societal net benefits from targeted electrification, with the potential for benefits for electric ratepayers being used to improve participant cost-effectiveness.

For this study, Ava Community Energy provided E3 with customer data across the eleven candidate sites (1,500 customers), on historical electricity and natural gas usage, building type, square footage, and rate enrollments. E3 used this data to estimate the distribution of bill impacts, avoided and incurred marginal utility costs, and emission savings from targeted electrification across customers. To estimate avoided gas infrastructure replacement costs, E3 worked with PG&E to identify the length of gas mains to be decommissioned at each candidate site using the utility's GIS-based GAS Asset Analysis Tool, along with the latest publicly

[3] Interruptible tariffs allow the utility to instruct customers to reduce or eliminate gas consumption during periods of high demand or service disruptions, and are offered as a cheaper alternative typically to larger industrial or commercial customers.
[4] Pacific Gas and Electric (PG&E) is the gas utility serving Ava Community Energy customers.

available main replacement $/mile costs.[5] E3 modeled both upfront avoided costs and lifetime gas revenue requirement savings from main decommissioning.

Figure 1 below shows the costs and benefits associated with targeted electrification, using California's modified total resource cost (mTRC) test, averaged across customers examined. This figure highlights the significant cost savings from avoided gas pipeline replacements, and the potential of these savings to offset the incremental customer and utility costs of electrification. This estimate does not include administration costs, which could be significant in this context and would reduce the societal cost-effectiveness of the targeted electrification project. These net benefits persisted across candidate sites, as shown in Figure 2, which explores the relationship between TRC cost-effectiveness and customer density, or customers per mile of main. The lower the customer density, the greater the relative avoided gas infrastructure savings per customer, highlighting the promise of prioritizing low-density portions of gas distribution networks for targeted electrification.

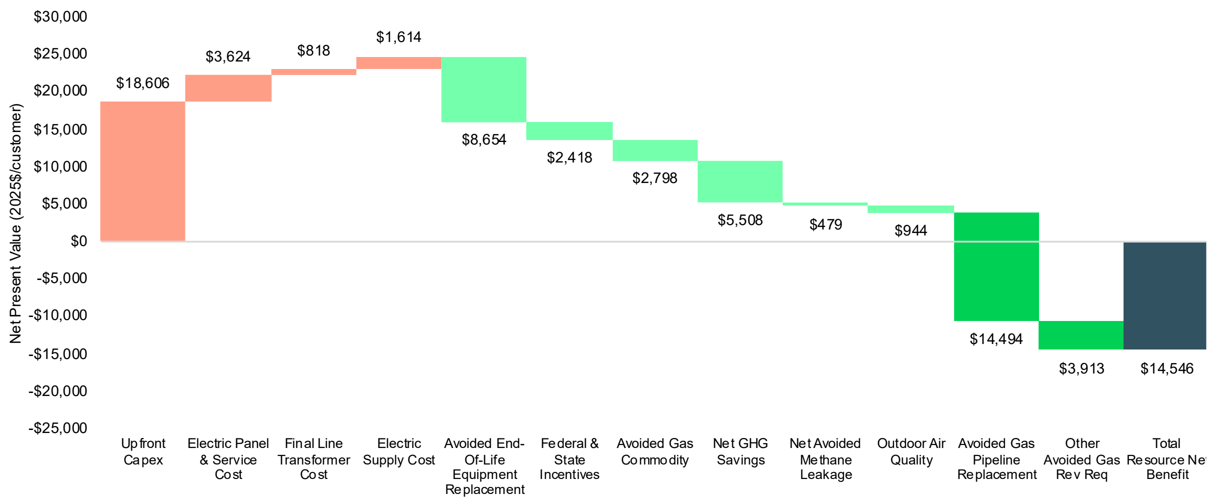

Figure 1. TRC Average Lifecycle Costs and Benefits per Customer

While the TRC cost-effectiveness of targeted electrification for these sites was clear, this study also highlighted the challenges faced by participants due to high incremental equipment costs, including electric panel upgrades. While the report highlighted that gas and electric ratepayer cost savings can be repurposed to improve participant economics (e.g., through higher incentives), it also underscored the need for reforming the utility obligation to serve, as the projects evaluated would not be able to proceed if even a single customer opted not to participate. Subsequent to this report, Senate Bill 1221 was passed, which allows gas utilities in California to develop up to thirty targeted electrification pilots by July 2026, requiring two-thirds of customers to consent to the pilot projects, reducing the implementation barrier for these projects.

[5] $4.72M/mile in $2023, from https://www.cpuc.ca.gov/industries-and-topics/natural-gas/long-term-gas-planning-rulemaking.

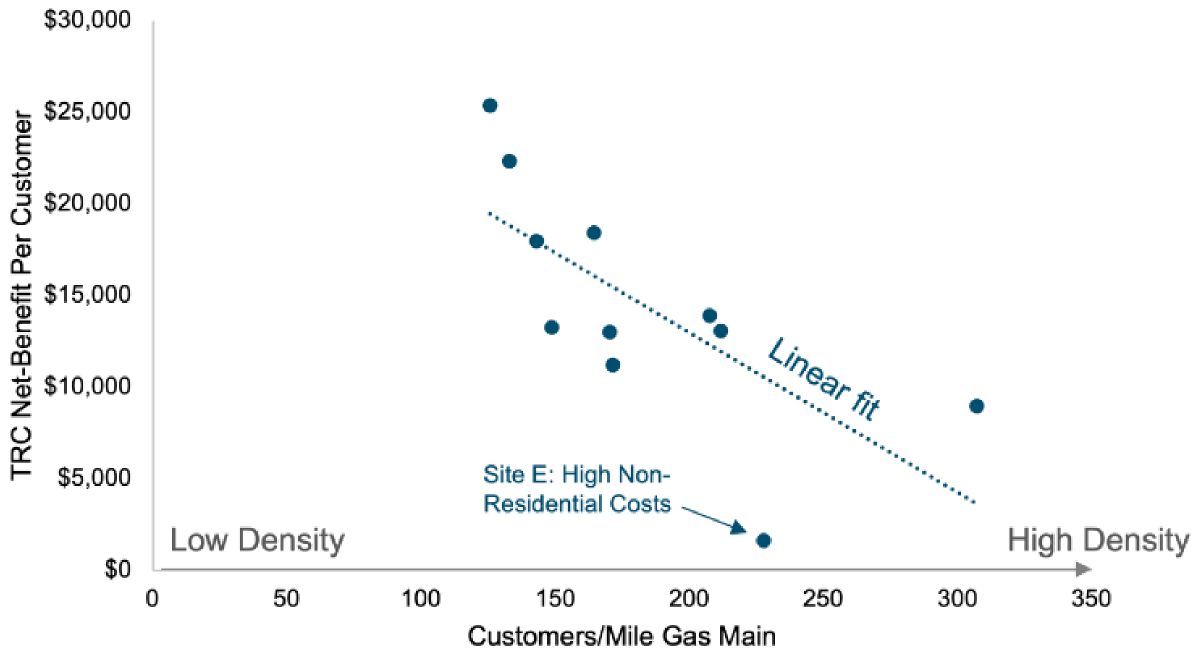

Figure 2. TRC Net Benefits per Customer vs. Customer Density for Each Candidate Site

Capacity Reduction, Rhode Island

In 2025, E3 provided testimony on behalf of Rhode Island Energy (RIE), assessing the viability and cost-effectiveness of NPA solutions to an existing liquified natural gas (LNG) vaporization facility at Old Mill Lane in Aquidneck Island, Rhode Island (Aas and Gresham 2025). The testimony analyzed demand-side measures and strategies to reduce peak natural gas demand on Aquidneck Island to mitigate the design day gas capacity shortfall that has driven the need for LNG vaporization infrastructure. While most NPA analyses are considered in lieu of planned gas system investments (e.g., replacements or upgrades), this NPA would only have avoided future operations and maintenance costs – no avoided capital costs were considered at this site. However, as discussed below, we believe the benefit-cost analysis result would ultimately be robust to inclusion of capital costs, if considering additional LNG storage facilities.

For this analysis, E3 developed an NPA measure supply curve tool, quantifying and comparing the potential and costs of different measures to reduce peak gas demand, as well as considering implementation challenges for each measure. RIE customer billing and demand forecast data were used to segment customers and estimate class-specific peak demand, while public data informed equipment costs, demand reduction impacts, and avoided marginal utility supply and delivery costs, as well as emissions.

Unlike the previous CEC targeted electrification project described, this NPA analysis sought to reduce demand across a disparate group of customers to reduce the need for peak capacity resources, thus avoiding the implementation challenges of requiring complete customer participation. While avoided pipeline replacement projects require complete gas displacements, capacity reduction projects such as this can leverage a wider set of measures such as energy efficiency and demand response, in addition to electrifying individual gas end uses. This allows for portfolios of measures to be assembled to meet the design day capacity shortfall, balancing measure cost-effectiveness and implementation feasibility. For example, the weatherization and gas efficiency measures that were evaluated, as well as demand response measures, reduced peak demand by a limited amount but yielded net societal benefits. In comparison, replacing gas furnaces with cold-climate heat pumps led to a far greater reduction of peak gas demand, as space heating accounted for 95% of peak gas demand, but yielded societal net costs, due to high equipment upfront costs and incurred electric delivery costs.

The portfolios developed to meet the capacity shortfall explored the tradeoffs of costs and feasibility across measures. Electrification-centric portfolios required fewer customer conversions but yielded greater ratepayer and societal cost, while portfolios emphasizing weatherization and gas efficiency required significantly more customer participation but yielded lower societal cost. Ultimately, all portfolios examined required levels of adoption in a short span of time that significantly exceed historical adoption rates, thus necessitating high utility equipment incentives and raising concerns about cost shifts to other ratepayers. E3 examined a range of adoption scenarios, reflecting existing empirical observations of uptake at high incentive levels ("lower customer uptake"), and higher levels of adoption that may be unlocked with high enough incentives to ensure no incremental equipment cost ("higher customer uptake"). These market shares were developed looking at historical maximum Clean Heat Rhode Island and Mass Save adoption rates achieved of 11% and 15% respectively, scaling up achievable adoption rates linearly as a function of incentive dollars offered per household. The subsequent annual adoption rates modeled were 30% for the "lower customer uptake" case and 60% for the "higher customer uptake" case, reflecting uncertainty around customer uptake at incentives that led to zero incremental upfront equipment costs. An example portfolio developed is shown in Figure 3, while Table 2 details the cost-effectiveness of and measure deployment required across all scenarios examined. Differing fulfillment years are a product of the annual uptake limits and mix of measures modeled.

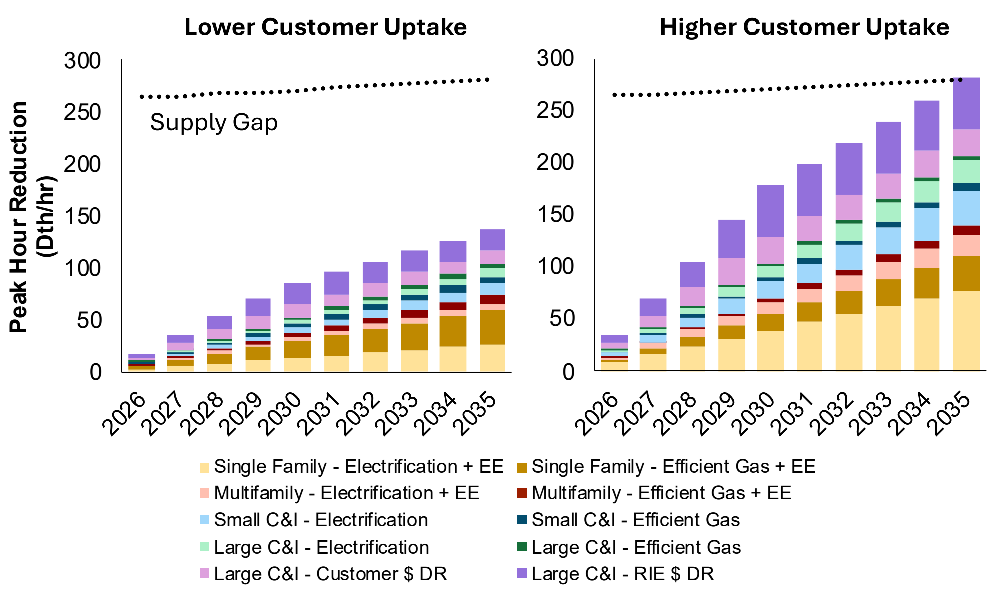

Figure 3. Portfolios Developed for Least Cost Scenario for RIE NPA Analysis, 2026-2035

Table 2. Scenario Design and Benefit-Cost Analysis for RIE NPA Analysis (Higher Customer Uptake Cases)

Portfolio Metrics ***High Uptake Cases***	**Lower Cost**	**Expanded Electrification**	**No New Fossil Equipment**
	Emphasis on gas efficiency and demand response	*Balance of electrification, gas efficiency, and demand response*	*Emphasis on electrification measures*
Design Hour Gap Fulfillment Year	2035	2034	2034
Cost Results ($2025 NPV)			
Portfolio Cost[6]	$68M	$78M	$80M
Societal Net Cost[7]	$65M	$102M	$125M
Utility Net Cost[8]	$126M	$158M	$172M
Approximate Number of Customers Affected (% of Total Customers)			
Residential Electrification + Energy Efficiency (EE)	2,060 (17%)	3,080 (25%)	3,700 (30%)
Residential Efficient Gas + EE	2,740 (22%)	1,230 (10%)	-
Small C&I Electrification	180 (12%)	275 (18%)	330 (22%)
Small C&I Efficient Gas	245 (16%)	110 (7%)	-
Large C&I Electrification	6 (12%)	9 (18%)	11 (22%)
Large C&I Efficient Gas	8 (16%)	4 (7%)	-
Large C&I Demand Response (DR)	20 (38%)	12 (22%)	6 (11%)

[6] Includes program incentive costs necessary to achieve the modeled measured uptake. 4.9% real discount rate assumed, aligned with utility weighted average cost of capital.
[7] Societal Cost Test, including benefits and costs for the utility, customers, and emissions reductions. 2% real social discount rate assumed.
[8] Utility Cost Test, including benefits and costs impacting the utility revenue requirement including incentives, electric supply and capacity, avoided gas supply. 4.9% real discount rate assumed, aligned with utility weighted average cost of capital.

While the RIE NPA scenarios shown above all yielded net societal costs, future capacity projects could yield successful NPAs, especially if key, favorable conditions are present:

- High avoidable gas infrastructure costs (e.g., transmission pipelines that would need to be replaced without capacity reduction)
- Long lead times to support measure uptake
- Adequate gas distribution system pressure if the capacity resource is retired.

This analysis assessed NPA cost-effectiveness and viability for retiring existing LNG infrastructure. If evaluating an NPA of a new or replacement LNG peaker facility, the inclusion of facility capital costs could plausibly significantly increase the value proposition of the NPA. However, we believe that in many cases, avoiding new LNG peakers would not necessarily change the benefit cost analysis results to show net benefits under any of the three benefit cost perspectives. For example, applying a $1.12/scfd peak delivery cost for new infrastructure[9] to the RIE LNG facility capacity of 5.62 mmscfd would yield an approximate capital cost of 6.29M ($2024). As shown in Table 2, the net costs of implementing NPA portfolios exceed this estimate by 10 to 20 times.

A simple way to contextualize LNG infrastructure costs is to estimate the costs per customer served; assuming 1,000 scfd per customer, the range of LNG costs above would yield a cost of approximately $1,100 per customer served. This remains far below the incremental per-customer cost of electrification equipment relative to gas equipment replacement (widely varying, often assumed to be ~$10,000 per cold-climate heat pump).[10] This demonstrates a key insight: while gas utility peak supply strategies are known to be expensive on a $/unit of gas basis, they are relatively cheap on a $/customer basis relative to demand side strategies that can provide similar levels of peak mitigation.

Third Party Analyses

While NPA deployment across the country has been limited to date, there are several examples of third party NPA analyses to better understand key drivers of NPA cost-effectiveness. These studies broadly came to the same conclusion as our studies, for each project type: the targeted electrification study (Zero Gas) was cost effective, while the Demand Reduction projects are not. However, the Demand Reduction projects could be more feasible (though still challenging) to implement at scale, since Demand Reduction projects have high customer opt-in requirements but do not require 100% participation like the Zero Gas projects.

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[9] While publicly available cost estimates are limited, two examples from New York and Virginia can provide a useful range of equipment replacement costs to directionally assess how the RIE capacity reduction NPA cost-effectiveness would change with avoided LNG infrastructure costs. In 2024, National Grid estimated $70M in gas infrastructure capital costs for an LNG vaporizer in Brooklyn, NY, with 60 mmscfd in Greenpoint, yielding an approximate cost of $1.16/scfd (NY DPS n.d.). In 2024, Dominion Energy Virginia, estimated $547M in total gas infrastructure costs for an LNG vaporizer with 500 mmscfd in Brunswick and Greensville, VA, yielding an approximate cost of $1.09/scfd (SCC n.d.).

[10] "Heat pumps for all? Distributions of the costs and benefits of residential air-source heat pumps in the United States." Wilson, Eric J.H. et al. (2024) Joule, Volume 8, Issue 4, 1000 - 1035. Available at: https://docs.nlr.gov/docs/fy24osti/84775.pdf

In PG&E's Monterey Bay zonal electrification application (CPUC A.22-08-003), the utility compared the electrification investments at CSU Monterey Bay to the cost of replacing aging gas distribution infrastructure. In its filing, PG&E reported an NPV of electrification costs of approximately $14.4 million and NPV benefits of approximately $15.4 million, defined primarily as avoided gas pipeline replacement costs, resulting in a benefit - cost ratio (BCR) of about 1.07 and a modest net benefit to gas customers (PG&E 2023). The analysis shows that significant avoided pipeline replacement costs drive project cost-effectiveness. Higher benefits could have been quantified if considering avoided air pollution and greenhouse gas reductions – potentially yielding a more comprehensive valuation of project outcomes.

Avoiding service line replacements through electrification is a type of Zero Gas NPA that could provide customer incentives without the need to gain 100% opt-in between neighboring buildings. Costs per service replacement vary substantially between utilities, with RMI (2025) estimating between $4,100 and $39,000 in a review of five utilities.[11] These values may not represent the avoided cost, as the utility may also incur potentially significant abandonment costs to complete the NPA. Con Edison has what we believe to be a first in the nation service line NPA program that provides single family customers with $10,000 in financial incentives to facilitate upgrades of non-space heating electric appliances,[12] demonstrating a significant avoided cost and substantially improving the customer economics of electrification.

Avista also conducted an NPA analysis of constrained gas areas in Washington to avoid pipeline expansions to meet increasing peak capacity needs (Avista Corporation and Cadmus Group 2025). The utility identified a least-cost demand-reduction portfolio, however, the modeled NPA costs substantially exceeded conventional system reinforcement costs. In South Hill, cumulative NPA costs are approximately $1.03 million compared with about $250,000 for expansion; in Dishman Mica, NPA costs are roughly $351,000 versus $30,000 - $50,000 for expansion - indicating the NPA portfolio is several times more expensive on a direct cost basis (Avista Corporation and Cadmus Group 2025). These NPA analyses are based on explicit adoption assumptions, including maximum energy efficiency applicability of 85% and demand response applicability of 9.5% - 18% (sector dependent), with demand response ramping at 10% per year under a business as usual case and 20% under an accelerated case. While the analysis does not fully monetize broader environmental or societal benefits, the magnitude of the cost differential suggests that including such benefits would be very unlikely to change the least-cost conclusion under the utility's screening framework.

In the Public Service Company of Colorado (PSCo) Mountain Energy Project (Xcel Energy n.d.), the utility is advancing a demand reduction strategy that couples non-pipe alternatives (NPAs) with modular supplemental supply options such as compressed natural gas (CNG) and liquefied natural gas (LNG) to address localized capacity constraints. The area affected by the project serves approximately 33,500 customers within Xcel Energy's Eastern Mountain Gas

[11] Based on discussions with utilities not represented in the RMI review, it's possible that this large range reflects differences in whether the service replacement costs quoted are done in conjunction with gas mains replacements. Efficiencies in project planning and equipment & personnel mobilization when done in conjunction with mains replacements would typically reduce the costs to toward the lower end of the range quoted by RMI ,based on these discussions. Depending on the utility, more expensive standalone service replacements may be less common.

[12] This incentive is in addition to existing heat pump incentives, with the intent of incentivizing electrification of all gas equipment to facilitate avoiding the service line replacement.

System (PUC n.d. Xcel). The study projects that by 2033, cumulative adoption would need to reach 61.6% for more efficient furnaces and boilers, 9.8% adoption of air-source heat pumps, and adoption of less than 1% of customers for ground-source heat pumps (Public Utilities Commission of the State of Colorado 2025, 61). When evaluated on a direct cost basis, this combined approach is estimated to cost approximately 1.15x times the cost of a traditional pipeline reinforcement.[13] This does not include greenhouse gas and air pollution reduction benefits. Importantly, roughly half of the combined cost is attributable to the modular supplemental supply components, which, in theory, could be redeployed to other constrained areas in the future if ongoing electrification and energy efficiency progress reduces the need for supplemental supply at the current location. This flexibility in modular supply underscores a potential strategic value beyond the initial cost comparison.

Barriers to Expansion of Non-Pipeline Alternatives

At present, substantial barriers limit the large-scale implementation of both targeted electrification and demand reduction NPA projects. Overcoming these challenges will require comprehensive reforms to utility planning, legislation and regulation reforms to fully realize the potential benefits of a targeted electrification or demand reduction NPA program.

Across jurisdictions and project types, customer uptake of building electrification trails the adoption levels required to meet near-term economy-wide decarbonization targets. Utilities attempting to deploy NPAs face the challenge of customer hesitation to electrify due to high incremental upfront costs of electric devices and associated household panel upgrade costs, high volumetric electric delivery rates, and workforce limitations (Bastian and Cohn). Furthering NPA deployment will require a coordinated effort to address each of these issues to improve electrification adoption levels more broadly, which will in turn significantly improve the feasibility of NPA deployments.

For targeted electrification projects, the primary impediment to NPA deployment is the gas utility's obligation to serve. Under prevailing interpretations for most states,[14] a utility would be unable to advance a targeted electrification project without unanimous opt-in from all customers, a threshold that is exceptionally difficult to meet for programs at any significant scale for both financial and consumer preference reasons. Other utilities have similarly identified the difficulty of executing targeted electrification projects that involve more than 5 customers (RMI and National Grid 2024). Accordingly, policymakers would need to evaluate reforms to the obligation to serve if targeted electrification projects are to be executed at a significant scale. California's SB 1221, discussed previously, provides one example of possible reform, whereby the project can proceed with opt-in from two-thirds of affected customers. The same challenge applies less to Demand Reduction NPAs, where demand reduction can be distributed across a wider customer base served.

[13] Public Service Company of Colorado. *Mountain Energy Project Filings and Supplemental Supply Description.* PSCo describes a hybrid portfolio of non-pipeline alternatives and modular CNG/LNG supply in its Mountain Energy Project proceeding before the Colorado Public Utilities Commission, estimating the combined approach at ~1.15× the cost of traditional pipeline reinforcement and noting the deployable nature of modular supply components.

[14] An exception to this case is California, where S.B. 1221 permitted gas utilities to proceed with zonal electrification pilots with two thirds of customers consenting to participation.

For Demand Reduction projects, a unique challenge to consider is the function played by the asset being assessed for an NPA in maintaining safe operating pressure for neighboring parts of the gas distribution system. Peaking resources at the edge of service territories that may be considered promising NPA candidates may play an important role in maintaining sufficient pressure for customers served by terminal mains. Retiring these assets may necessitate additional investments to ensure the network of pipelines serving remaining customers maintains safe operating pressure, thus reducing the avoided costs associated with an NPA. These operational challenges and mitigation strategies will become increasingly evident as more Demand Reduction NPAs are deployed across utility service territories. These issues can be improved if higher levels of unrelated electrification are achieved within and potentially outside of the immediate project area.

Uncertainty about utility cost recovery for NPA costs also remains a challenge for aligning utility incentives with NPA deployment. NPA costs could include marketing and outreach costs, gas infrastructure abandonment costs, behind-the-meter measure incentives, and electric delivery infrastructure upgrade costs, all of which would necessitate clear cost recovery mechanisms for utilities to feel comfortable pursuing NPA options. Example mechanisms could include revisions to removal cost recovery, expense treatment, regulatory assets, and benefit-sharing agreements. In addition, performance incentive mechanisms could be considered to support the successful implementation of targeted electrification projects. The design of these mechanisms will carry significant financial implications for both utilities and ratepayers. In a similar vein, a key consideration with NPA cost recovery is determining how customer incentive and program administration costs should be allocated across electric and gas ratepayers. Allocating a greater share to electric customers could reduce downward pressure on electric rates from electric load growth. Conversely, assigning a larger portion to gas customers could erode the gas system savings intended to reduce gas rate impacts, particularly as gas throughput declines due to decarbonization and electrification efforts in other areas. Allocation of costs between gas and electric ratepayers becomes much more difficult where separate gas and electric utilities serve the project area.

Conclusion

Non-pipeline alternatives, or NPAs, are initiatives designed to avoid new gas infrastructure investments or enable the retirement of existing gas assets by reducing gas consumption. They can serve as a cost management strategy for the gas system, particularly in scenarios where widespread building electrification results in fixed system costs being recovered from a shrinking customer base. In such cases, a portion of the infrastructure costs avoided through NPAs can be redirected to fund electrification or energy efficiency investments.

A review of E3 and other third-party projects indicates that NPA opportunities generally fall into two categories: Zero Gas NPAs and Demand Reduction NPAs. Each category involves different planning considerations, program designs, and implementation approaches. Zero Gas NPAs are intended to fully eliminate gas service within defined, relatively small geographic areas such as individual blocks or neighborhoods. These approaches avoid investment in gas mains and service lines and depend on comprehensive electrification, networked geothermal systems, and in some cases delivered fuels. In contrast, Demand Reduction NPAs are structured to reduce peak gas demand sufficiently to defer or avoid major infrastructure investments driven by peak load requirements across larger service areas. These strategies rely on a broader portfolio of measures, including energy efficiency improvements, demand response, electrification, and alternative fuels.

The implementation challenges also differ. Zero Gas NPAs require universal or near-universal customer participation within the targeted area, while Demand Reduction NPAs must achieve sustained reductions in peak demand despite underlying load growth and development trends. Zero Gas NPAs so far have shown to have much higher avoidable costs per customer than Demand Reduction NPAs. Existing examples of Demand Reduction NPAs so far have not demonstrated project cost-effectiveness because existing peak supply strategies remain cheaper on a per customer basis than demand side strategies capable of achieving similar scales of peak load mitigation.

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