EXH. DAV-1T
DOCKETS NOS. UE-260005 & UG-260006
2026 PSE GENERAL RATE CASE
WITNESS: DANIELLE A. VELEZ

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKET NOS. UE-260005 and UG-260006 (*Consolidated*)

RESPONSE TESTIMONY (NONCONFIDENTIAL)

OF DANIELLE A. VELEZ

ON BEHALF OF JOINT ENVIRONMENTAL ADVOCATES

July 28, 2026

JOINT ENVIRONMENTAL ADVOCATES

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I. <u>INTRODUCTION AND SUMMARY</u>

Q. Please state your name and business address.

A. My name is Danielle A. Velez, and my business address is 111 Sutter Street, 21st Floor, San Francisco, California 94104.

Q. By whom are you employed and in what position?

A. I am the Equitable Gas Transition Lead for the Natural Resources Defense Council (NRDC), where my work focuses on managing an equitable, affordable transition from the fossil gas system to clean, all-electric buildings.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of NW Energy Coalition, Front and Centered, Sierra Club, Washington Conservation Action, and Climate Solutions (collectively the Joint Environmental Advocates, or JEA).

Q. What is your preferred form of address?

A. I use she/her pronouns and am comfortable being addressed as Ms. Velez.

Q. Please give a brief description of your professional experience and education.

A. I serve as NRDC's lead expert on gas utility system decarbonization policies, involving a deep understanding of related clean energy issues, such as building electrification, green hydrogen policy, clean electricity, and utility regulation. I have represented NRDC in more than twenty-five regulatory proceedings across the West and Midwest, and I hold a Bachelor of Science in Atmosphere and Energy Engineering from Stanford University. Please refer to my resume, Exhibit DAV-2, for a full list of my qualifications.

Q. Have you previously testified before this Commission?

A. No, I have not.

Q. Have you testified before any utility commissions in other states?

A. Yes. I have testified before the California Public Utilities Commission, the New Mexico Public Regulation Commission, and the Colorado Public Utilities Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is twofold. First, I propose a Service Line Non-Pipeline Alternative (NPA) Program, through which Puget Sound Energy (PSE) would offer households impacted by planned gas service line replacements an incentive to electrify instead of having their gas service line replaced by default. The incentive would be sized to reduce utility costs compared to the pipe replacement that would otherwise take place—thus saving money for all gas customers while advancing Washington's climate goals.

Second, I respond to PSE's proposals for two gas system pilots: a Thermal Energy Network (TEN) pilot and a hydrogen blending pilot. I recommend approving the TEN pilot but not the hydrogen blending pilot because the former includes sufficient detail to justify approval, complies with applicable statutory requirements, and presents a viable path toward decarbonizing parts of the gas distribution system, but the latter does not.

Q. Please summarize your Service Line NPA Program proposal.

A. I recommend that the Commission require PSE to establish a Service Line NPA Program that offers gas customers impacted by a planned gas service line replacement an incentive of $16,500, or $18,500 for residents of Named Communities, to switch to all-electric appliances rather than have their gas line replaced. PSE plans to replace at least 735 gas service lines over the Multi-Year Rate Plan (MYRP)—the vast majority of which serve a single residential gas meter.[1,2] Each service line replaced through the Distribution Integrity Management Plan

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[1] Exh. DAV-18 (PSE Response to JEA Data Request (DR) 18) at § c.viii.
[2] Exh. DAV-19 (PSE Response to JEA DR 19) at § c.

(DIMP) will have a lifetime cost to gas customers of $21,323 (net-present value, or NPV), and service lines replaced through other programs will cost as much as $40,000 (NPV).[3] PSE expects to recover these costs over at least 45 years, heightening the risk of stranded gas assets as Washington transitions to net-zero emissions.

Offering customers an alternative to these pipeline replacements is a commonsense measure that will cut emissions while saving all PSE gas customers money. I estimate that my proposed program would save gas customers at least $4.4 million (2026) while also avoiding $2.4 million in social costs of methane and carbon. As such, adopting the Service Line NPA Program is a highly effective way of implementing the Washington Utilities And Transportation Commission's (UTC) order from PSE's 2024 rate case "requir[ing] that PSE evaluate non-pipeline alternatives when considering capital additions to the natural gas system outside of emergency and maintenance repairs."[4] I recommend that the Commission direct PSE to implement the program with a $3.54 million budget drawn almost entirely from PSE's requested DIMP project budget, as a condition of approving PSE's budget request for DIMP projects.

The Service Line NPA Program is a practical and ready-to-implement solution that can draw on program design models from a similar New York program and build on PSE's targeted electrification proposals. Because the UTC's prior order requires evaluation of NPAs for these DIMP capital additions, and because the Service Line NPA Program satisfies the UTC's lowest reasonable cost standard while advancing state policy, directing PSE to implement it will ensure that the rates approved through this MYRP are just and reasonable.

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[3] My gas service line lifetime cost calculations are discussed in Section I.B. of this testimony and presented in Exh. DAV-4 (Service Line NPA Cost Analysis Tool), see tab "Service Line NPVs."
[4] UTC, Docket UE-240004, Order 09/07 at ¶ 329.

II. SERVICE LINE NON-PIPELINE ALTERNATIVE (NPA) PROPOSAL

A. Summary of Program Need, Structure, and Benefits.

Q. Please describe the problem that your Service Line NPA Program is designed to solve.

A. Today, PSE replaces old gas service lines—the vast majority of which serve a single residential meter—by default, regardless of whether the affected customer is likely to leave the gas system in coming years.[5,6] A gas service line replaced in 2027 has an expected lifetime of at least 45 years,[7] meaning all PSE customers will continue paying for it until at least 2072. This is decades after Washington's goal of carbon neutrality by 2050.[8]

Gas service lines connect customers to the gas distribution system

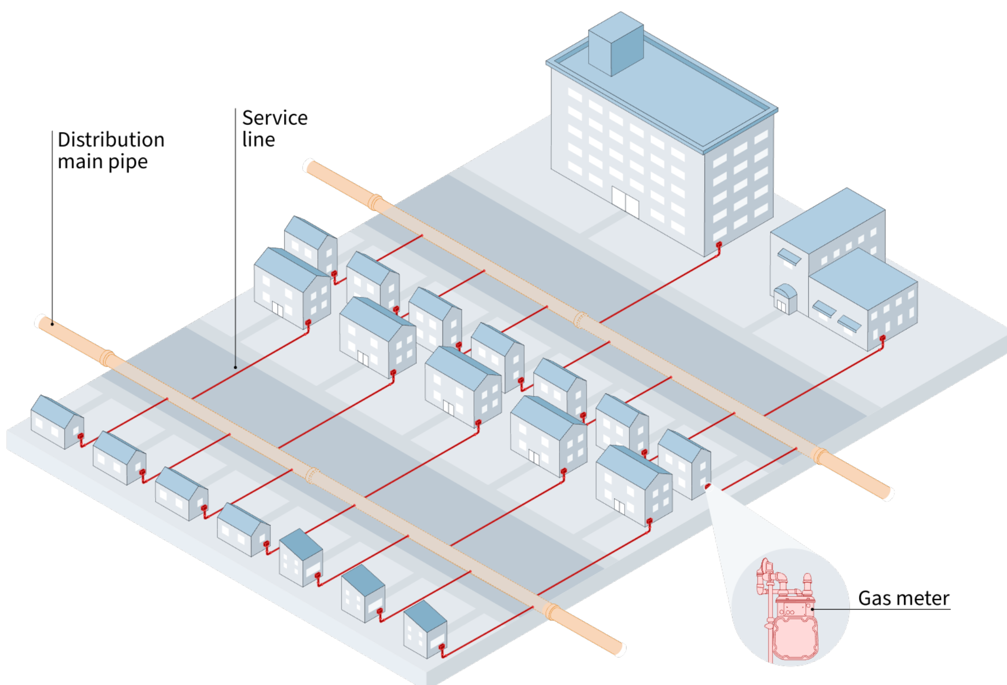

Figure 1: *Gas Service Line Illustration, courtesy of RMI.*

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[5] *See* Exh. DAV-18 (PSE Response to JEA DR 18) at § c.viii.
[6] *See* Exh. DAV-19 (PSE Response to JEA DR 19) at § c.
[7] *See* Exh. DAV-9 (PSE Response to JEA DR 21) at § c.
[8] *See* RCW 70A.45.020.

This risks situations in which a customer's gas service line is replaced, and then they depart the gas system well before pipeline costs are recovered—driving up costs and stranded asset risk for all gas customers. My proposed Service Line NPA Program addresses this risk by offering households the opportunity to depart the gas system at the precise time when their departure will save all gas customers money by avoiding their service line replacement.

Q. Please describe your Service Line NPA Program proposal at a high level.

A. Under my Service Line NPA Program proposal, PSE would offer households facing a planned gas service line replacement a standard incentive of $16,500—or $18,500 for customers in Named Communities—to voluntarily electrify rather than proceed with a gas service line replacement. These incentive amounts are substantially less costly than a DIMP gas service line replacement, which I calculate, based on data provided by PSE, to have an average lifetime cost of $21,323 (NPV). This calculation is discussed further in subsection B. Service line replacements executed through other programs, which are more emergent in nature, are even more costly.

To pay for the program, the Commission should direct PSE to redirect $3.3 million from their DIMP budget to this program and approve an additional $240,000 for the Service Line NPA Program (for a total program budget of $3.54 million). These values are based on an estimated participation rate of 200 customers, which is about a quarter of PSE's planned service line replacements for the MYRP cycle.[9] While the upfront cost of the program is slightly higher than the service line replacement budget, my program proposal delivers substantial lifetime savings to customers in the form of avoided gas revenue requirement, as discussed below.

[9] *See* Exh. DAV-18 (PSE Response to JEA DR 18) at § c.v. and further discussion in Section B.

Q. Please summarize the main benefits of your Service Line NPA Program proposal.

A. First and foremost, the program will create significant savings for PSE customers. At my proposed incentive levels, I calculate that a Service Line NPA Program that electrifies 200 customers will deliver at least $4.4 million ($2026) in savings (or nearly $1 million, in NPV terms) to PSE customers in the form of avoided gas revenue requirement over the lifetime of the avoided gas assets. The savings are so substantial because PSE customers would avoid paying the utility a rate of return on the pipeline over its 45-year depreciation period,[10] and they would also avoid the meter replacement costs and annual operational & maintenance (O&M) costs associated with a service line replacement.

Second, the Service Line NPA Program will deliver significant health and climate benefits. I estimate the program will produce $2.4 million in avoided social costs of carbon and methane, in addition to the customer savings described above. In light of the state's climate targets, it is imprudent to continue investing in long-lived gas pipelines that serve a single household without offering the customer the opportunity to pursue a lower-cost, safer, and cleaner alternative.

Finally, the program avoids many of the complexities of multi-customer NPAs while laying the foundation for success in future NPAs and electrification programs. Unlike neighborhood-scale NPAs that require coordination across multiple households, the Service Line NPA Program can proceed, in the vast majority of cases, with consent from a single property owner. Service lines are also terminal branches of the gas distribution system and therefore can be retired in a streamlined fashion without presenting hydraulic feasibility

[10] 45 years is PSE's proposed financial depreciation lifetime for gas service line investments in this MYRP. The current depreciation life for PSE's gas service lines is 50 years. *See* Exh. DAV-9 (PSE Response to JEA DR 21) at §§ b. & c.

concerns.[11] Moreover, customers facing gas service line replacements through DIMP are frequently also slated for a gas main replacement to their neighborhood, making it possible for the Service Line NPA Program to unlock even greater savings by improving PSE's ability to implement larger-scale neighborhood electrification projects down the line.

Q. Please summarize your recommendations for program implementation.

A. In implementing the Program, PSE can draw on the example of Consolidated Edison's (Con Edison) Energy Exchange Program, a similar initiative that is being implemented in New York. Xcel Energy in Colorado and Pacific Gas & Electric in California have proposed similar programs that will likely lead to additional examples in the near future. Following these examples, PSE should prioritize outreach to customers who have already participated in an electrification program, low-income customers, customers in Named Communities, customers with historically low gas usage, and customers with more than six months lead time from their service replacement.

For simplicity, I propose for the program to be funded with PSE's operational expense budget, as is current practice for PSE building electrification incentives, and for costs to be recovered from gas customers, since the program repurposes funds that would have otherwise been spent on gas infrastructure. As discussed further in Section D, to support program expansion, the Commission might also consider authorizing PSE to recover the program's incentive costs as a regulatory asset that is depreciated over 10 years at PSE's approved rate of return.

[11] *See* Exh. DAV-20 (PSE Response to JEA DR 130).

Q. Do you expect all customers who are offered a Service Line NPA incentive to accept it?

A. No, but this is by design and does not reduce the benefits of this no-regrets program. The program likely will not cover the full cost of home electrification in all cases, so I anticipate that some customers will not choose to accept the incentive and disconnect their gas service. This is one reason why I assume only 200 customers participate over the MYRP when estimating the program's benefits. However, it is common sense to offer households the opportunity to electrify, rather than automatically re-investing customer money in gas pipelines. Additionally, because PSE will not need to conduct any customer-specific NPA analysis in order to offer a standardized incentive that by design has lower costs than the service line replacement, there are no downsides to offering the incentive.

Q. Does the Commission have authority to order PSE to implement a Service Line NPA Program?

A. While I am not an attorney, I understand that the Commission is authorized by RCW 80.28.425(1) to "approve, approve with conditions, or reject, a multiyear rate plan proposal made by a gas or electrical company or an alternative proposal made by one or more parties, or any combination thereof." In considering multiyear rate plan proposals, the Commission applies its broad discretion to establish rates and practices that are just, reasonable, sufficient, and in the public interest.[12] In PSE's 2024 general rate case, the Commission determined that the public interest requires PSE to evaluate non-pipeline alternatives when considering gas

[12] *See* RCW 80.28.020; *see also* RCW 80.01.040(3) (providing that the Commission shall "[r]egulate in the public interest").

capital additions, pursuant to "its duty to acquire the lowest-risk resources, consistent with state policies, including the CCA and directives in HB 1589."[13]

A substantial portion of PSE's requested DIMP budget will go towards service line replacements, and PSE has not demonstrated that it evaluated non-pipeline alternatives to these investments as required by the UTC's 2024 order. My testimony shows that PSE can feasibly and cost-effectively avoid many of these costs and substantial emissions through a Service Line NPA Program. It would not be just, reasonable, or in the public interest to approve PSE's requested DIMP budget without modifications or conditions when lower-cost alternatives are available. Conversely, directing PSE to implement a Service Line NPA Program as a condition of approving its requested DIMP budget fits within the Commission's authority to "approve with conditions ... a multiyear rate plan proposal ... or an alternative proposal made by one or more parties"[14] in order to ensure that enacted rates are in the public interest.

I understand the Commission "generally does not preapprove or otherwise direct investments or acquisitions by a utility."[15] I do not believe that approving the proposed Service Line NPA Program would amount to "directing investments." First, NPAs are not investments or acquisitions but tools to avoid costly capital investments. Second, the Commission's main concern with directing investments is the potential to frustrate its prudency review of investments.[16] Rather than frustrate prudency review, ordering a Service Line NPA Program as a condition of DIMP budget approval is an exercise of prudency review of the requested DIMP budget. Indeed, insofar as PSE's budget request is for the costs of future service line replacement projects that will occur during the multiyear rate plan period, the Commission is

[13] UTC, Docket UE-240004, Order 09/07 at ¶ 329.
[14] RCW 80.28.425(1).
[15] UTC, Docket UE-240004, Order 11/09 at ¶ 62.
[16] *Id*.

equally well-positioned to determine the prudence of non-pipe alternatives to these investments as to determine the prudence of the investments themselves.

Q. What will you discuss in the remainder of this section?

A. In the remainder of this section, I will describe the opportunities for service line NPAs in PSE territory, expand upon my proposed implementation and cost recovery structure for the Service Line NPA Program, and present the modeled costs and benefits of my proposal.

B. Service Line NPA Opportunities in PSE Territory

Q. How many gas service lines will PSE replace over the MYRP period?

A. I forecast that the Company will replace nearly 2,000 gas service lines over the 3-year MYRP period.[17] While this is a small portion of total gas connections, avoiding a percentage of these pipe replacements would deliver significant climate and health benefits while substantially reducing costs and stranded asset risks for all gas customers.

I derived this forecast as follows. First, PSE states that it plans to replace 245 gas service lines through DIMP programs each year of the 3-year MYRP period, which amounts to 735 total replacements.[18]

Second, PSE's forecast does not include certain DIMP sub-programs under which, the Company states, "service line replacements have occurred historically but are not a primary remediation activity."[19] While not included in the Company's formal estimates, data provided

[17] My calculations are presented in Table 1 below and in Exh. DAV-5 (Service Line Data Compiled), see tab "Planned Forecasts."
[18] *See* Exh. DAV-18 (PSE Response to JEA DR 18) at § c.v.
[19] These include "Bridge and Slide Unmaintainable Facilities, Buried Meter Remediation, Idle Riser Remediation, Inside Meters, PE Pipe Recall 1-inch, Planned Corrosion Remediation, Unmaintainable Regulator Stations, and Unmaintainable Steel Main in Casing." *Ibid*.

by PSE show that since 2017, the Company has replaced an average of 60 services lines per year through these additional DIMP programs.[20]

Third, the Company's forecast also does not include service lines that may be replaced via the Gas Operations and Public Improvement investment types, since service line replacements through these programs are "largely emergent in nature and are driven by system conditions, customer activities, and municipal public improvement projects."[21] However, based on historical data provided by PSE, the Company replaced an average of approximately 340 gas service lines per year as part of these programs between 2017–25.[22,23]

Altogether, I calculate that the Company will replace approximately 2,000 gas service lines over the MYRP period (Table 1). Thus, my proposed target of avoiding 200 service line replacements through the Service Line NPA Program represents about a quarter of PSE's officially planned replacements and about a tenth of the replacements I have forecasted.

Table 1. Expected Service Line Replacements Over MYRP Period

Replacement Category	Rate Year 1	Rate Year 2	Rate Year 3
PSE's Forecasted Replacements through DIMP	245	245	245
Expected Additional Replacements Based on Historical Spending (DIMP)	60	60	60
Expected Additional Replacements Based on Historical Spending (Gas Operations and Public Improvement)	340.3	340.3	340.3
MYPR Total	**1936**		

These replacements will take place as part of the following programs:

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[20] *See* Exh. DAV-5 (Service Line Data Compiled), which derives historic replacement averages based on data provided by PSE's response to JEA's DR 18 (Exh. DAV-7 (PSE Response to JEA DR 18_Attach A) at §§ c.i, iii, iv).
[21] Exh. DAV-18 (PSE Response to JEA DR 18) § c.v.
[22] *See* Exh. DAV-5 (Service Line Data Compiled).
[23] PSE also installs an average of about 84 service lines per year through the Customer Construction investment type, but I exclude this type from my calculations because it may include new customer gas line extensions. *See* Exh. DAV-21 (PSE Response to JEA DR 129).

Table 2. Programs That Include Gas Service Line Replacements[24]

Investment Type	Program Name
Gas Operations	Field Identified Remediation
	Leak Repair
Distribution Integrity Management Program	Bridge and Slide Unmaintainable Facilities
	Buried Meter Remediation
	Dupont Pipe Remediation
	Idle Riser Remediation
	Inside Meters
	Low Pressure Remediation
	Mobile Home Encroachment Program
	Older Steel Remediation
	PE Pipe Recall 1-inch
	Planned Corrosion Remediation
	Shallow Service and Main Remediation
	Unmaintainable Facilities
	Unmaintainable Farm Taps
	Unmaintainable Regulator Stations
	Unmaintainable Steel Main in Casing
Customer Construction	Customer Construction
Public Improvement	PI Driven Relocation of Facilities

Q. What is the average cost to replace a gas service line in PSE territory?

A. The average cost to replace a gas service line in PSE territory varies by investment category. PSE states that in 2025, the average loaded cost (inclusive of any overhead and indirect costs) to replace a gas service line as part of DIMP was approximately $16,500.[25]

[24] *See* Exh. DAV-18 (PSE Response to JEA DR 18) § b.
[25] Exh. DAV-18 (PSE Response to JEA DR 18) § d. PSE alternatively states that its "planning-level estimate for the average loaded cost of replacing a gas service line is approximately $15,000, escalated annually over the MYRP period." *Id.* at § c.vii.

Meanwhile, gas service line replacements completed via the Public Improvement investment category, which "involve relocation of existing facilities to accommodate municipal infrastructure projects," cost an average of $31,600 per line.[26,27]

Q. Do these costs represent the lifetime cost that customers will pay for a service line replacement?

A. No, the costs provided above are the upfront cost to replace a gas service line under different investment categories, not the lifetime cost. Over a pipeline's lifetime, PSE collects much more than the upfront cost from customers. Additional costs collected from customers fall into three main categories.[28]

First, gas service line costs are currently collected over an average service life of 50 years.[29] Under PSE's cost recovery proposal for the MYRP, this would be changed to 45 years.[30] Each year until the pipeline is fully paid off, PSE earns a rate of return on the undepreciated value of the pipeline. PSE's currently approved rate of return, after tax, is 7.08%.[31] PSE's proposed return for the MYRP is higher: 8.09% for Rate Year 1, 8.15% for Rate Year 2, and 8.18% for Rate Year 3, averaging to 8.14% per year.[32] Over time, this translates to a substantial profit collected from gas customers on their bills.

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[26] *Id*.
[27] Service line replacements completed via the Customer Construction investment type cost approximately $18,000 per line—however, these installations include both service line replacements and new customer connections. Exh. DAV-21 (PSE Response to JEA DR 129).
[28] As part of a gas pipeline investment, PSE also collects a "net salvage value" that is calculated as the expected salvageable value of the pipeline materials at the end of its life minus the anticipated cost of retiring the pipeline. In my cost calculations, I do not include decommissioning costs for the retiring pipeline (in the case an NPA is pursued) or the net salvage value that would be collected as part of a pipeline investment (in the case the pipe replacement moves forward), for the reasons discussed in the Response Testimony of JEA Witness Bradley T. Cebulko (Exh. BTC-1T) and in Section 5.2 of my Methodology Paper (*see* Exh. DAV-3 (Service Line NPA Cost Analysis Tool Methodology Paper)).
[29] Exh. DAV-9 (PSE Response to JEA DR 21) § b.
[30] *Id*. at §§ c, a.
[31] Exh. DAV-15 (PSE Response to JEA DR 25) § a.
[32] *Id*.

Second, gas service line replacements are currently accompanied by gas meter replacements, "subject to meter availability."[33] Gas meter replacement costs range from $220–$360 per meter.[34] Meter replacement costs are also treated as capital expenses—meaning they earn a rate of return.[35] They are depreciated over 40 years.[36]

Finally, after a gas service line is replaced, PSE spends approximately $34 per year per service line on O&M costs, including activities such as leak survey, corrosion control, maintenance, and related overhead.[37]

Taking into account each of these factors, Table 3 below presents the lifetime cost to customers of gas service line replacements completed under both the DIMP and Public Improvement investment types. I present lifetime costs under both PSE's proposed cost recovery structure for this MYRP (45-year depreciation at 8.14% return) and their current cost recovery structure (50-year depreciation at 7.08% return). These values were calculated using my Service Line NPA Cost Analysis Tool, provided as executable Exhibit DAV-4 and discussed further in Section E below. I present lifetime costs in both 2026 dollars and net present value terms.[38]

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[33] Exh. DAV-18 (PSE Response to JEA DR 18) § c.ii.
[34] Exh. DAV-8 (PSE Response to JEA DR 20) §§ a, b.
[35] *Id*.
[36] *Id*.
[37] Exhibit DAV-13 (PSE Response to JEA DR 23) § a.
[38] For full results for these model runs, *see* Exh. DAV-4 (Service Line NPA Cost Analysis Tool), tab "Service Line Costs."

Table 3. Service Line Replacement Lifetime Costs

Service Line Replacement Category	Upfront Cost	Lifetime Cost ($2026)	Lifetime Cost (Net Present Value)
DIMP (Proposed Cost Recovery)	$16,500	$39,814	$21,323
DIMP (Current Cost Recovery)	$16,500	$37,740	$19,384
Public Improvement (Proposed Cost Recovery)	$31,600	$74,418	$40,049
Public Improvement (Current Cost Recovery)	$31,600	$70,356	$36,345

Q. What is Net-Present Value, or NPV?

A. Calculating the Net-Present Value (NPV) of revenue requirement is a commonly accepted method of determining the total lifetime cost to customers of a utility investment. Taking the "NPV" converts the lifetime cost savings, which occur in the future, to a present value that accounts for the "time value of money" to utility customers. "Time value of money" refers to the principle that a dollar today is worth more than a dollar in the future. My modeling assumptions, including the discount rate applied in my NPV calculations, are discussed in detail in my NPA Cost Analysis Tool Methodology Paper, Exhibit DAV-3.

Q. Based on your review of PSE's planned service line replacements, which investment type should the Service Line NPA Program focus on?

A. At minimum, the Service Line NPA Program should be offered to gas customers facing an officially planned gas service line replacement through DIMP over the MYRP period. DIMP replacements are already forecasted by PSE, which expects to complete a total of 735 replacements over the MYRP.[39] Under PSE's proposed cost recovery framework, each replacement would cost gas customers about $21,300 (NPV) over its lifetime (Table 3).

[39] *See* tbl. 1.

Additionally, PSE states that "[t]he majority of Distribution Integrity Management Program service line replacements are performed in conjunction with planned main replacement projects"—laying the groundwork for potential neighborhood-scale NPA projects down the line.

Establishing a Service Line NPA Program focused on planned DIMP replacements is a no-regrets option that will be administratively simple to implement this MYRP cycle, and I focus the majority of my testimony and cost analysis on this recommended program design. However, I encourage the Commission to additionally require PSE to offer the Service Line NPA Program to customers impacted by non-forecasted replacements under both the DIMP and Public Improvement investment types. As discussed previously, PSE characterizes these replacements as emergent in nature and therefore does not include them in their official forecast for the MYRP. However, PSE has historically executed approximately 400 of these "unplanned" service line replacements each year, and Public Improvement replacements are particularly costly.

Therefore, if more than six months of lead time is available before an emergent pipeline replacement must be completed, PSE should offer an electrification incentive to the impacted customer through the Service Line NPA Program. While shorter lead time may lead to lower uptake among these customers, there is no reason not to offer the incentive, and any Public Improvement projects avoided through the program will produce even greater savings than planned DIMP replacements. Service line replacements through the Public Improvement investment type have a lifetime cost of about $40,000 (NPV) under PSE's proposed cost recovery framework, which is more than double the proposed $16,500 incentive.

In the future, the Commission may consider increasing the incentive amount offered for Public Improvement projects to increase participation and reflect the greater avoided gas infrastructure costs of these projects. In Section E below, I discuss the potential structure and cost savings of such a future program focused on Public Improvement projects. In the following sections, I will discuss my proposed Service Line NPA Program in greater detail, including my proposed program implementation and the program's estimated cost savings, rate impacts, and emissions benefits.

C. Proposed Service Line NPA Program Design.

Q. What incentive amount do you propose for your Service Line NPA Program?

A. I propose that PSE implement a Service Line NPA Program that offers a standardized incentive offering of $16,500, with an enhanced offering of $18,500 for customers who reside in a Named Community. In my program cost modeling discussed throughout this section, I assume that 50% of participants will reside in a Named Community and 50% will not, resulting in an average incentive amount of $17,500. This assumption reflects my proposal that the program prioritize outreach to households that are low-income and/or disproportionately impacted by environmental harms.

Q. How should the Commission authorize a program budget for the Service Line NPA Program?

A. The Commission should direct the Company to establish a Service Line NPA Program as a modification to the Company's MYRP budget request. The Commission should reduce PSE's requested DIMP budget by $3.3 million, which reflects the expected savings from a Service Line NPA program that avoids at least 200 DIMP service line replacements, each of which cost an average of $16,500.

Those DIMP budget reductions should be redirected to establish a budget for the Service Line NPA Program. The program's total budget would be $3.54 million, which is slightly larger than the $3.3 million redirected from the DIMP program. This budget includes $200,000 to cover the enhanced offerings for customers in Named Communities ($2,000 for each of the 100 targeted Named Community participants) and $40,000 available for administrative budget. Any unspent program funds would be returned to gas customers as savings.

Despite having a nominally higher upfront cost, the program will save gas customers more than $4.4M ($2026), or $1M in NPV, compared to the lifetime costs of the gas pipelines that would otherwise be replaced. In other words, while the dollar amount approved is technically higher, the program greatly reduces the amount of revenue collected from customers over time. This is because, as discussed throughout this testimony, gas customers pay a significant amount in utility rate of return and O&M costs over the decades-long lifetime of a gas pipeline, and these substantial lifetime costs would be avoided by the service line NPA, whose costs would be collected in one year. The program's cost savings will be even higher than my estimates if incentives are taken up by customers facing a Public Improvement service line replacement, which are more costly than DIMP replacements, as discussed in the previous section. Details of my cost-benefit analysis are discussed further in Section E below.

Notably, if the Commission rejects PSE's proposed $3.4 million hydrogen blending pilot as I recommend below, it could fully fund the Service Line NPA Program without increasing the overall revenue requirement compared to PSE's requested amount.

Q. Why is $40,000 an appropriate administrative budget for the Service Line NPA Program?

A. $40,000 is an appropriate administrative budget because the program requires minimal effort to implement and can leverage existing administrative efforts. PSE has already developed a targeted building electrification program, as discussed in the Testimony of Aaron A. August, which offers an $8,000 incentive for electric heat pumps. The program includes "enhanced marketing campaigns, a referral bonus program for installers, and targeted trade ally engagement and training."[40] As part of this MYRP, PSE is requesting Commission approval to recover $17.24 million in costs for that program.[41]

In addition, gas service line replacements already require outreach from the gas utility to affected customers, and PSE has already established a forecast for service lines that they will replace through DIMP this MYRP. These existing customer eligibility data and outreach efforts and materials can be utilized in implementation of the Service Line NPA Program, reducing the cost to implement the program.

Finally, the Service Line NPA Program is, by design, simple to implement and does not require any project-by-project cost-effectiveness analyses, instead relying on a standardized incentive offering. For all of these reasons, I believe that $40,000, which amounts to $200 per customer for program implementation, is a reasonable administrative budget for the Service Line NPA Program.

In Section E below, I discuss a sensitivity that I modeled in which I increase the administrative budget for the program to $500 per project, or $100,000 total, and I increase the average electrification incentive to $22,000. The Service Line NPA Program is still cost-

[40] PSE Exh. AAA-1T (Aaron A. August Opening Testimony) at 76, lines 9–10.
[41] *Id*. at 79–80.

effective at these cost levels, indicating that the Commission could approve a higher program budget for administrative costs and incentives if desired while still retaining the significant affordability benefits of my proposal.

Q. Please describe your proposed implementation for the Service Line NPA Program.

A. Program implementation elements should include:

- A means for gas customers to verify their eligibility for the Program, such as through an email inquiry to a designated representative or an online look-up tool;
- Customer outreach that includes information on the air quality and health benefits of electrification, with additional outreach provided to low-income customers, customers in Named Communities, customers with low gas load, customers that have participated in other building electrification or energy efficiency programs through PSE, and customers with more than six months of lead time prior to their planned service replacement.
- A list of potential contractors;
- A requirement for gas disconnection and gas meter removal as a condition of program participation; and
- Follow up surveys to enable incorporation of customer feedback to program design updates.
- A requirement that PSE update the incentive amount each year to account for inflation in the average cost of a gas service line replacement.

For purposes of approval as part of a decision on PSE's MYRP Application, the Commission could set higher-level program guidance and leave PSE to develop specific implementation details.

Q. What steps should PSE take to increase deployment of Service Line NPAs for Customers in Named Communities?

A. I recommend an enhanced incentive of $18,500 for customers in Named Communities. PSE should also focus targeted outreach, such as site visits and phone calls, on customers in Named Communities, with wider-reaching marketing methods, such as email and mailers, extended to larger populations of eligible customers. PSE should ensure that community outreach provides information about the benefits of electrification in a manner that is linguistically and culturally appropriate, building on the principles identified in PSE's recently-filed Language Access Plan.[42] Within Named Communities, I recommend that PSE prioritize Service Line NPA Program incentives for low-income customers if funds are limited, potentially offering different incentive levels based on the tiers in PSE's bill discount program.

However, my proposed incentive is unlikely to cover the full cost of home electrification for low-income customers, particularly where electrification would include replacement of multiple gas appliances, electric work and home health and safety remediation. Accordingly, PSE should coordinate with program administrators of low-income ratepayer and non-ratepayer funded efficiency and electrification programs to maximize incentive layering. As recommended in the Response Testimony of Bradley T. Cebulko, PSE should also establish a General Electrification Program, and those incentives should be eligible for layering with the Service Line NPA offering.[43]

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[42] UTC, Docket UE-240004, Language Access Plan (March 30, 2026).
[43] Exh. BTC-1T (Response Testimony of Bradley T. Cebulko), *see* Section III.

Q. Is this proposed implementation consistent with the approach of similar programs in other jurisdictions?

A. Yes. Con Edison has a Service Line Replacement NPA program it markets as the Energy Exchange Program.[44] The program targets customers connected to the gas system via pre-1972 services and provides incentives to fully disconnect from the gas system.[45] Incentives provided under the Energy Exchange Program are as follows:[46]

Table 4: Con Edison Energy Exchange Incentive Offerings

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

Con Edison hosts a webpage for customers to submit interest forms and choose preferred contractors.[47] As set forth in Con Edison's Non-Pipes Alternative Implementation Plan, Con Edison implements the program through a network of pre-approved Participating Contractors with the following process:[48]

- Once the customer has selected a Participating Contractor, the contractor performs a site survey of the existing conditions and documents existing gas appliances.

[44] Exh. DAV-34 (Con Edison, *Non-Pipes Alternatives Implementation Plan*) at 12–13, also available at https://documents.dps.ny.gov/public/Common/VieCwDoc.aspx?DocRefId=%7B20D54093-0000-C55C-B8E2-2BBA133E981F%7D. *See also* Con Edison, *Energy Exchange Program*, available at 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).
[45] Attach. DAV-34 (Con Edison, *Non-Pipes Alternatives Implementation Plan*) at 12–13.
[46] Con Edison, *Energy Exchange Program*, *supra* at fn. 46.
[47] *Id*.
[48] *Id*. at 16–18.

- Following a site visit, the Participating Contractor works with the customer to decide on specific electric appliances to replace the existing gas appliances and review the necessary electrical work and gas piping/equipment removal.
- The Participating Contractor submits a program application, which is vetted to assess if electric service upgrades are required. Projects with adequate electrical service are granted a Preliminary Incentive Offer Letter (PIOL).
- Projects that require electrical service upgrades must allow the service upgrade to be completed before a PIOL is extended and installation can proceed. This process prioritizes safe and reliable electric service. After the customer and Participating Contractor review and accept the PIOL, the Company issues a blank Completion Certificate to be filled out and returned to the Company after installation is completed. A Participating Contractor can proceed with installation once they have received the Company's Completion Certificate.
- After installation, the customer must close their gas account and work with the Participating Contractor to request gas service disconnection and gas meter removal.
- The Company performs an inspection of the installation (on-site or desk review), performs the Final Review, then submits the project for payment.
- When full electrification of each customer is confirmed, the Company schedules the service to be disconnected, allowing the service pipe to be abandoned.

While specific implementation details can be left to PSE, the process by which Con Edison executes Service Line NPAs can serve as a model for a Service Line NPA program in Washington.

D. Cost Recovery of the Service Line NPA Program

Q. How should the Company recover the costs of the Service Line NPA Program?

A. The costs of the Service Line NPA Program (including both incentive and administrative costs) should be recovered from gas customers, similar to PSE's proposed DIMP budget. However, unlike PSE's DIMP budget, program costs should be recovered as operational expenses, as is current practice for PSE's building electrification incentives, rather than capital expenses.

First, it is appropriate to recover the costs of this program from gas customers because the program is an NPA, which delivers cost savings to gas customers in the form of avoided gas pipeline spending. It would violate cost causation principles to charge electric ratepayers for a program that is explicitly constructed to avoid gas system costs that would otherwise be paid by gas ratepayers. Other jurisdictions have generally allocated NPA costs to gas customers only. The Colorado Public Utilities Commission recently ordered Xcel to recover NPA costs only from gas customers "recognizing that it is only gas customers who would otherwise pay for a traditional gas infrastructure project."[49] Likewise, California utilities have proposed to recover NPA costs from gas customers so that NPAs "have a similar financial treatment to planned gas projects,"[50] and California's Senate Bill 1221 provides for NPA pilot costs to be recovered from gas utility customers.[51]

Second, it is appropriate to recover the incentive costs as operational expenses because this is consistent with PSE's existing recovery structure for building electrification programs, and therefore offers a straightforward cost recovery option for the Service Line NPA Program.

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[49] Colo. Pub. Util. Comm'n, Docket No. 25A-0220G, Decision No. C26-0371 at ¶ 206.
[50] Cal. Pub. Util. Comm'n, App. No. 22-08-003, *Amended App. of Pacific Gas and Electric Co. (U 39 G) for Approval of Zonal Electrification Pilot Project* at 9 (Dec. 19, 2022), available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M500/K435/500435462.PDF.
[51] Cal. Pub. Util. Code § 663 (directing the California Public Utilities Commission to establish a "requirement that gas corporations recover costs related to the pilot projects...").

Currently, "[t]he behind-the-meter costs of Puget Sound Energy's (PSE) targeted electrification programs, including customer rebates, incentives, and grants for heat pump installations, are recovered as operating and maintenance ('O&M') expenses, not capital expenditures."[52] Should the Commission wish to pursue an alternative cost recovery method for the Service Line NPA Program's behind-the-meter costs, I recommend that they consider authorizing PSE to collect the costs as a "regulatory asset" that is depreciated over 10 years at the utility's approved rate of return.

Q. Please define regulatory asset treatment.

A. Regulatory asset treatment would involve depreciating electrification incentive costs over an approved time period to smooth out near-term customer cost impacts. Because the costs would be collected over time, the Company would need to finance them. Therefore, the utility would collect their rate of return on the investment over its depreciation period. The investment is a "regulatory asset," rather than a capital expenditure, because the utility does not own the behind-the-meter (BTM) asset and is not responsible for its maintenance. The California Public Utilities Commission describes regulatory asset treatment as the utility "playing a pass-through role" by financing BTM investments that provide value to ratepayers, and that role "is based on ratepayers' promise to repay the utility."[53] Put differently, the scenario for the utility is "more akin to a temporary loan from the IOUs to ratepayers rather than an IOU investment in utility infrastructure."[54]

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[52] Exh. DAV-17 (PSE Response to JEA DR 27) § a.
[53] See, e.g., Cal. Pub. Util. Comm'n, Decision No.23-04-034, *Decision Adopting Implementation Rules for the Microgrid Incentive Program*, at 77 (Apr. 14, 2023), available https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M505/K732/505732868.PDF.
[54] *Id*.

There is precedent for this treatment of utility program costs. For example, the Colorado Public Utilities Commission recently approved amortization of NPA costs over 10 years.[55] In New York, the costs of Consolidated Edison's NPA programs, including their service line-focused NPA program, are recovered as regulatory assets over a 20-year period and are afforded the utility's standard rate of return, plus a shareholder incentive based on achieved cost savings.[56] I am not recommending a shareholder incentive here,[57] but I offer regulatory asset treatment as a potential method for encouraging PSE to implement this program effectively and balancing near- and long-term program cost impacts, as discussed further below.

Q. What would be the cost and rate impacts of a "regulatory asset treatment" approach?

A. There is a key trade-off to consider when determining how long to collect the costs of a utility investment. A simple comparison is to think of a utility investment as a loan. Paying $1 million upfront in Year 1, rather than taking on a loan, has a significant pocketbook impact in Year 1, but you avoid making interest payments in future years. Taking out a 10-year loan for $1 million, instead, reduces the amount you pay in Year 1, but it increases total lifetime cost because you pay interest on the loan over 10 years. Alternatively, taking out a 45-year loan for $1 million minimizes the amount you pay in Year 1, but greatly increases lifetime cost when considering all the interest that you will pay over the 45 years.

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[55] Colo. Pub. Util. Comm'n, Docket No. 25A-0220G, Decision No. C26-0371 at ¶ 206.

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

[57] This diverges from the recommendation in the Response Testimony of JEA Witness Bradley T. Cebulko, but it appropriate in this case because a main function of the shared savings mechanism is to incentivize cost control in NPA design. This is not necessary for the Service Line NPA, since it is designed to produce savings and would have a budget established by the Commission.

The 45-year scenario is akin to what PSE is proposing for service line replacements this MYRP cycle, which would be paid off as capital expenditures over 45 years. The 1-year scenario is akin to PSE's current treatment of behind-the-meter electrification costs, which I am proposing be approved for this program for simplicity. And the 10-year scenario is akin to the regulatory asset option that I am offering to the Commission for alternative consideration. The table below demonstrates the trade-offs of these approaches by showing the lifetime cost and Year 1 rate impacts of a $1 million PSE expenditure collected over 1, 10, and 45 years.

Table 5: Impacts of $1M Utility Investment with Varying Recovery Periods[58]

Cost Recovery Period	Upfront Cost	Year 1 Bill Impact	Lifetime Cost ($2026)	Lifetime Cost (NPV)
1 Year	$1,000,000	$1.22	$1,000,000	$1,000,000
10 Years	$1,000,000	¢23.45	$1,336,717	$1,045,622
45 Years	$1,000,000	¢15.35	$2,293,930	$1,240,391

As shown in **Table 5**, 1-year cost recovery has the highest near-term bill impact but minimizes lifetime costs. 45-year cost recovery has the lowest near-term bill impact but maximizes lifetime costs. And 10-year cost recovery strikes a balance. I recommend that the Commission approve program costs to be collected using operational expense budget over one year for consistency with the existing approach to cost recovery for PSE's electrification programs, and to minimize the total long-term cost of the program. Because the proposed program budget is small compared to PSE's overall revenue requirement and therefore will not significantly increase rates in the near-term, I believe the benefits of minimizing total long-term costs outweigh the small additional near-term costs that result from expensing the program costs in this case. However, I offer the 10-year regulatory asset treatment proposal as

[58] Exh. DAV-4 (Service Line NPA Cost Analysis Tool), *see* "Cost Recovery Comparison" tab.

a potential alternative that reduces the near-term cost impact of the program and offers the utility an incentive, in the form of rate of return, to pursue the program. Ultimately, the JEAs are comfortable with either expense treatment or 10-year amortization if the Commission or stakeholders prefer one over the other.

E. Modeled Costs and Benefits of the Service Line NPA Program

Q. Please briefly summarize the costs and benefits of your proposed Service Line NPA Program.

A. My modeling finds that an equity-focused Service Line NPA Program that delivers 200 building electrification incentives at an average cost of $17,500 per incentive would yield the following impacts:

- Lifetime gas system savings of at least $7.9 million (nominal dollars, $nom), or about $4.4 million in 2026 dollars,
- NPV savings of at least $1 million,
- NPV Social Cost Savings of approximately $2.4 million due to avoided carbon and methane emissions, and
- A Non-Participant Gas Bill cost of only $3.78 for the entire first year of the program, during which all program costs are collected. In reality, these costs and rate impacts would be spread over all three years of the MYRP, so the annual bill impacts would be even lower than $3.78.

Across all sensitivities modeled, the Service Line NPA Program delivers robust customer savings.

Q. Please briefly introduce your Service Line NPA Cost Analysis Tool.

A. My Service Line NPA Cost Analysis Tool is an Excel spreadsheet model that I developed to enable users to compare the annual revenue requirement and rate impacts of an NPA portfolio with a base case gas investment that would otherwise take place. The modeling assumes that gas ratepayers either pay for a base case gas investment or an NPA. The Tool also estimates the emissions impacts and associated societal costs of the NPA portfolio.

I based the Tool's calculations and my scenario inputs largely on information provided by the Company through discovery responses. I describe my methodology and sources in detail in Exhibit DAV-3. Notably, my model applies the simplifying assumption that all investments take place in the same year, even though I expect participation to be spread out across all three years of the MYRP. This assumption does not materially change the results of my modeling and will only minorly impact the NPV calculation. The Tool is available as executable Exhibit DAV-4, and users can easily run scenarios using their own inputs.

Q. Please summarize the assumptions that you inputted to the Service Line NPA Cost Analysis Tool.

A. To estimate the impacts of my proposed Service Line NPA Program, I inputted the following parameters:

Table 6: Service Line NPA Program Modeling Parameters

Key Input	Value	Explanation
Number of NPA Projects	200 projects	I assume that the Service Line NPA Program electrifies 200 households, which is about a quarter of PSE's officially forecasted gas service line replacements through DIMP over the MYRP.[59]
Avoided Service Line Cost per Project (CapEx)	$16,500	This is PSE's average DIMP service line replacement cost.[60] As discussed previously, the service line replacement cost for Public Improvement projects is much higher,[61] and I propose offering the NPA incentive to customers impacted by these projects, too, if at least 6 months lead time is available.
Avoided Gas Meter Cost per Project (CapEx)	$220	Gas service line replacements are frequently accompanied by gas meter replacements,[62] with costs ranging from $220-$360 per meter.[63] I assume the lower end meter replacement cost.
Avoided Annual O&M Cost per Project (OpEx)	$34 per year	PSE reports that $34 per year per line is their average cost to operate and maintain a gas service line.[64]
Gas Service Line Depreciation Period	45 years	PSE's proposed gas service line depreciation timeline for the MYRP is 45 years.[65]
PSE Rate of Return	8.14%	This is the average of PSE's proposed WACCs for each year of the MYRP.[66]
NPA Cost per Project (OpEx)	$17,700	I model a Service Line NPA Program that provides an equity-focused electrification incentive of $18,500 for Named Community customers and a non-Named Community incentive of $16,500, with a 50-50 split in uptake between equity and non-equity customers, for an average incentive of $17,500. I also assume $200 in administrative costs per project, as discussed in Section C above.

59 *See* tbl. 1.
60 Exh. DAV-18 (PSE Response to JEA DR 18) § d.
61 *See* tbl. 3.
62 Exh. DAV-18 (PSE Response to JEA DR 18) § c.ii.
63 Exh. DAV-8 (PSE Response to JEA DR 20) § a.

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

Q. Please discuss the lifetime cost impacts of the program.

A. The Service Line NPA Program results in cost savings of approximately **$4.4 million** ($2026) for utility customers. It yields the following year-over-year revenue requirement impacts:

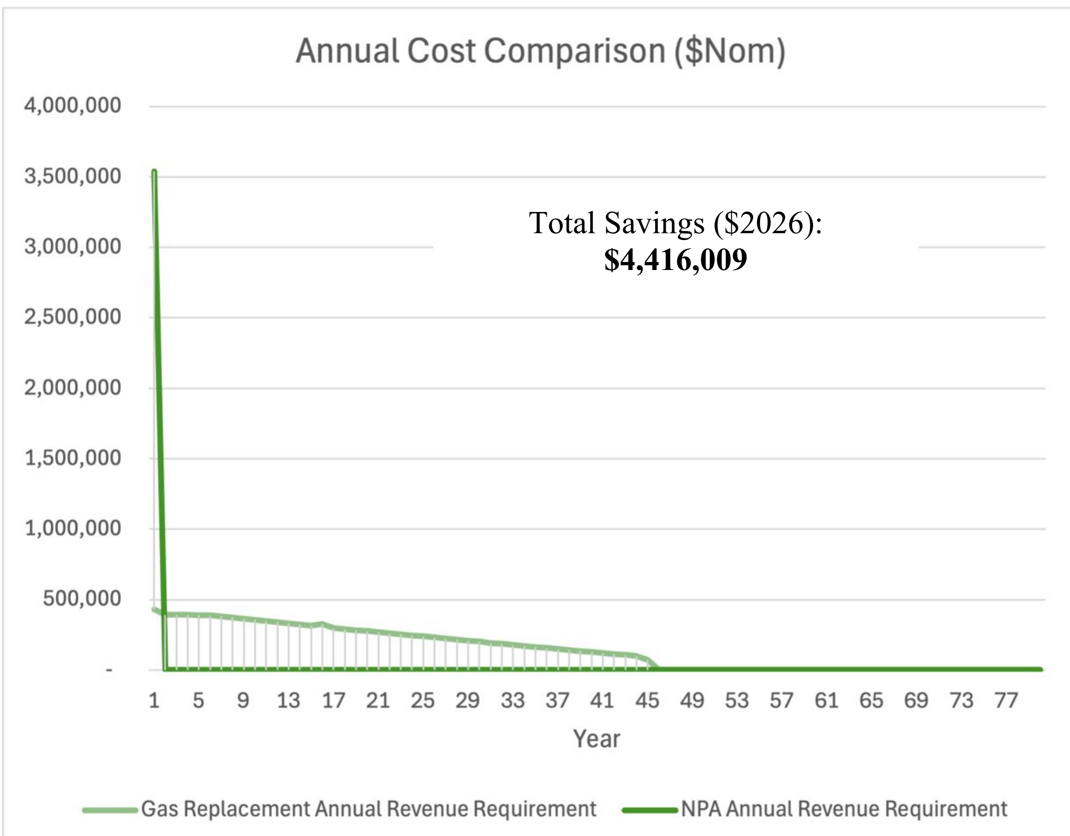

Figure 2: *Annual Cost Comparison ($Nom), Gas Replacement vs. Service Line NPA Program*

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[64] Exh. DAV-13 (PSE Response to JEA DR 23) § a.
[65] Exh. DAV-9 (PSE Response to JEA DR 21) § c.
[66] Exh. DAV-15 (PSE Response to JEA DR 25) § b.

As demonstrated in the figure above, the Service Line NPA Program yields significant lifetime savings—one can interpret the net area between the curves (indicated with gray stripes) as representing the lifetime cost savings of the Service Line NPA projects (NPA Annual Revenue Requirement) versus the otherwise-planned gas service replacements (Gas Replacement Annual Revenue Requirement). The NPA projects also significantly reduce stranded cost risk, since the NPA investment is paid off by ratepayers over one year, as compared to the assumed 45-year depreciation life of the counterfactual gas service line replacements. In all, the Service Line NPA Program delivers nearly $1 million (NPV) in savings to gas customers compared to the pipeline replacements that would have taken place. Cost results are summarized in **Table 7** below. Notably, the savings of the program will be even greater if customers facing service line replacements through Public Improvement projects, which are more costly than DIMP projects, accept the offered incentive.

Table 7: Key Cost Outputs, Gas Replacement vs. Service Line NPA Program[67]

Key Cost Outputs	
Total Cost, Gas Replacement ($Nominal)	$ 11.5 M
Total Cost, NPA ($Nominal)	$ 3.5 M
Total Savings ($Nominal)	$ 7.9 M
Total Savings ($2026)	$ 4.4 M
Avoided Return on Investment ($Nominal)	$ 7.6 M
Total Savings (NPV)	**$ 972 thousand**

[67] Exhibit DAV-4 (Service Line NPA Cost Analysis Tool), *see* “Scenario Results” tab.

Q. Please discuss the modeled rate impacts of the program.

A. To evaluate the long-term rate impacts of adopting the NPA program, I considered two background gas throughput scenarios: (1) a Gas Transition Scenario that assumes PSE's residential customer gas throughput declines 67% by 2050 and (2) a Business-as-Usual (BAU) Scenario in which electrification does not substantially increase in the future. The BAU Scenario is included for comparison, but would not be a lawful or valid option under Washington law. The Gas Transition Scenario aligns with PSE's Hybrid Heat Pump Scenario which, as discussed in the Response Testimony of Bradley T. Cebulko, represents a conservative estimate of reductions in gas throughput as Washington decarbonizes in line with statutory targets.[68]

The Service Line NPA Program yields significant long-term rate benefits in both scenarios, but the Gas Transition Scenario highlights the affordability benefits of investing in an NPA rather than re-investing in long-lived gas assets as Washington transitions away from gas. If gas throughput decreases faster than PSE's Hybrid Heat Pump scenario, then rate impacts in the Gas Replacement Case (Gas Transition Scenario) shown below would be even greater. Notably, I assume that the 200 households that participate in the Service Line NPA Program depart the gas system, thus slightly reducing annual gas throughput and customer count even in the BAU Scenario. The results of these scenario runs for both the Gas Replacement Case and the NPA Case are presented in the figure below:

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[68] Referring to workpaper in support of PSE Exh. NWA-4 (Exhibit 260005-06-PSE-WP-NWA-4-3-6-2026-Public - Puget - Gas Planning Model (R).xlsx), *see* "Consumption" tab, cells CB71–CB97.

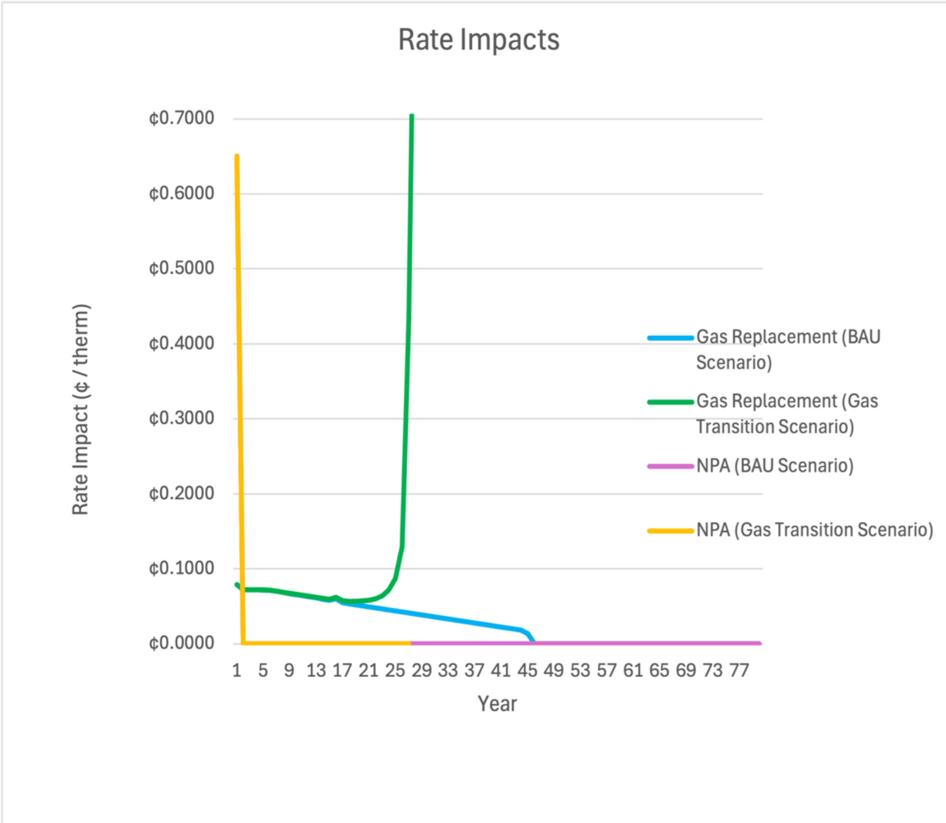

Figure 3: *Rate Impacts, Gas Replacement vs. Service Line NPA Program, with All Service Line NPA Costs Collected in Year 1*

In the graph above, rate impacts are presented in cents, reflecting the negligible near-term rate impact of the Service Line NPA Program. While my recommended program increases rates in Year 1 compared to gas replacement (because NPA costs are collected in the year they are incurred, and the model assumes all projects occur in Year 1), the increase is small. A non-participating gas customer would pay only about $3.78 extra on their annual gas bill over the entirety of the MYRP to fund the program. Conversely, under the Gas Transition scenario, the rate impact of the counterfactual gas service line replacements increases significantly over time, as households depart the gas system in line with Washington's pressing climate goals.

Q. How would the revenue requirement and rate impacts of the Service Line NPA Program differ if the Commission approves 10-year regulatory asset treatment?

A. If the Commission is concerned about the near-term rate impact of the program, they could authorize PSE to collect the costs of the electrification incentives as a 10-year regulatory asset (as discussed in Section D above). If the Commission approves regulatory asset treatment for behind-the-meter program costs, then non-participating gas customers will only pay an additional $0.35 on their bills over the entire first year to fund the program.[69] In every subsequent year, the bill impact of the program will decrease as the investment is paid off, until it is fully depreciated in Year 10, as shown in Figures 4 and 5 below. Under this cost recovery structure, the program still delivers $3.2 million ($2026) in lifetime savings (which translates to $567,000 in NPV terms) for all PSE gas customers. Full results for this scenario are presented in the "Scenario Run" tab of my NPA Cost Analysis Tool.[70]

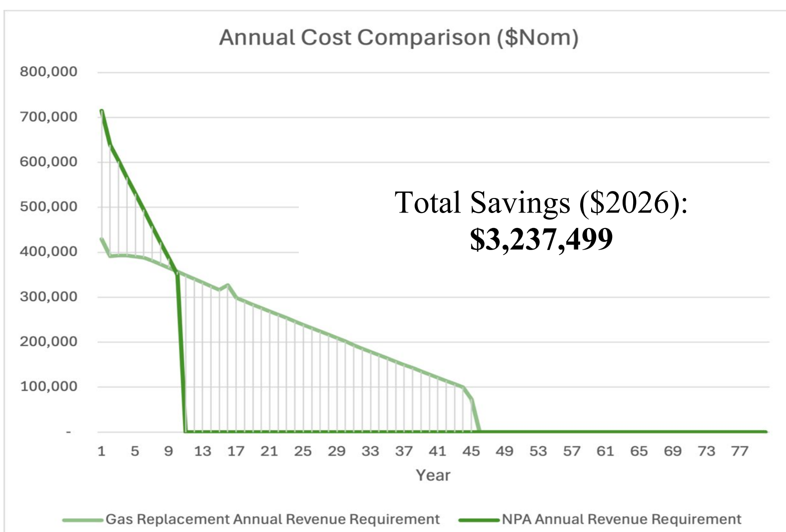

Figure 4: *Revenue Requirement Impacts, Gas Replacement vs. Service Line NPA Program, with Service Line NPA Costs Collected over 10 Years*

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[69] Exhibit DAV-4 (Service Line NPA Cost Analysis Tool), *see* "Scenario Runs" tab, § 3 (10-Year Regulatory Asset Treatment for NPA scenario).

[70] *Id.*, *see* cells F74–83.

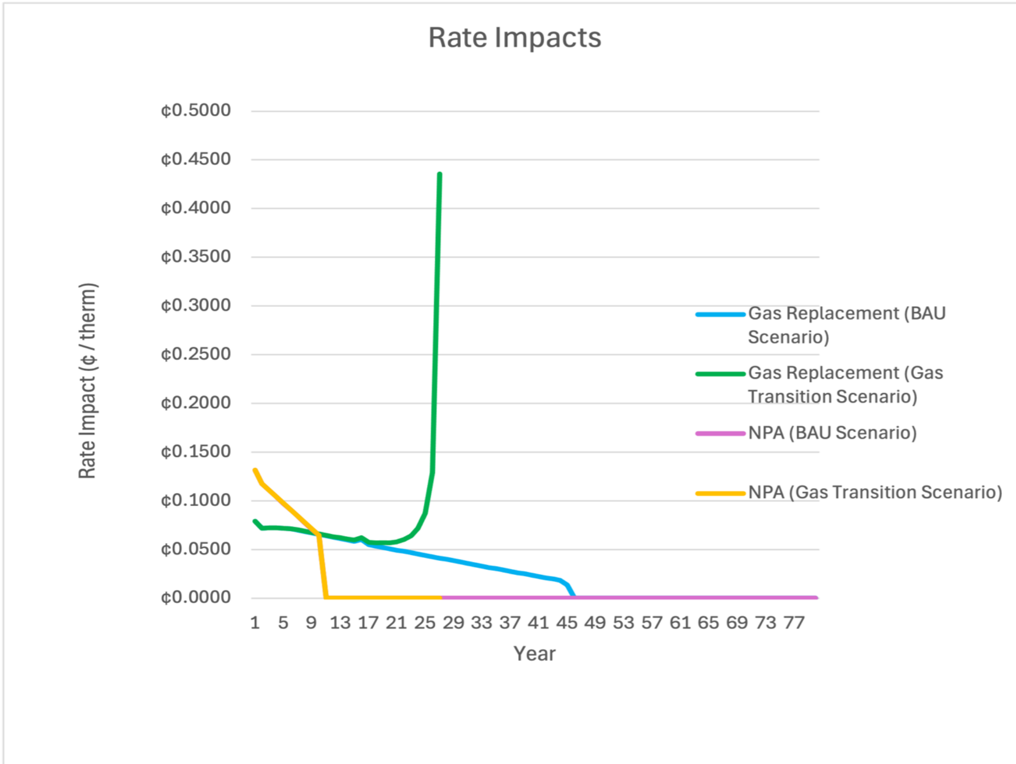

Figure 5: *Rate Impacts, Gas Replacement vs. Service Line NPA Program, with Service Line NPA Costs Collected over 10 Years*

Q. Is the Program still cost-effective under different parameters?

A. Yes. To understand how the cost-effectiveness of the proposed Service Line NPA Program would vary under different program design and cost inclusion assumptions, I modeled numerous alternative scenarios. The program is still cost-effective under all of the following scenarios:

1. **Higher NPA Costs:** Even if the average incentive is increased to $22,000 and administrative costs are increased to $500 per project, the program still delivers about $80,000 (NPV) in savings.

2. **10-Year Regulatory Asset for NPA:** As discussed above, the program still delivers about $567,000 in NPV savings if the NPA costs are recovered as regulatory assets over 10 years.
3. **Higher Participation**: Increasing program participation to 1000 households increases NPV gas customer savings to $4.9 million and increases the climate benefits of the program. It also increases the Year 1 bill impact to about $19 per customer for the entire first year of the program. This Year 1 bill impact reduces to only $1.74 if costs are recovered as 10-year regulatory assets.
4. **NPV Discount Rate Set to Utility ROR:** The program still delivers $60,000 in NPV savings if a higher discount rate (utility ROR) is applied for the NPV calculation.
5. **Lower Service Line Replacement Costs:** Even if the avoided replacement cost per service line is reduced to $15,000, and meter costs are excluded, my program still delivers about $600,000 in NPV savings.

Results of these and other alternative scenarios are available in the "Scenario Runs" tab of my NPA Cost Analysis Tool, and the Tool can easily be updated to test alternative assumptions per the instructions in the spreadsheet and the accompanying methodology document.

Q. Are there other social benefits of the Service Line NPA Program that are not quantified above?

A. Yes. The Service Line NPA Program would reduce annual carbon dioxide emissions by about 700 metric tons per year and would reduce annual methane emissions by about 0.03 metric tons per year, resulting in **NPV social cost savings of about $2.36 million**. I describe the methodology behind my emissions and social cost calculations in detail in Exhibit DAV-3, Section 4. Moreover, reducing gas combustion results in health benefits and avoided CCA allowance costs that I did not quantify in my modeling.

Q. What would be the impacts of a program that offers incentives to avoid service line replacement expected through the Public Improvement investment type?

A. While I recommend, at minimum, establishing a program focused planned DIMP replacements, I encourage the Commission to go further by directing PSE to offer Service Line NPA incentives to households impacted by a foreseeable service line replacement via a Public Improvement project. While I recommend initially offering the standard incentive amount of $16,500 (or $18,500 in Named Communities) to customers that would be impacted by a Public Improvement project, in the future the Commission could consider increasing the incentive amount offered to these customers to reflect the significantly greater avoided gas infrastructure costs in this category. I will briefly summarize the modeled benefits that such a program could achieve.

As previously discussed, the average cost to replace a service line through Public Improvement is $31,600, which is higher than through DIMP. Therefore, a Service Line NPA Program focused on these replacements could offer a higher incentive in the future. I modeled a program that avoids 200 Public Improvement service line replacements by offering an electrification incentive of $30,000 per project, plus $200 per project in administrative costs. I find that a program with this structure would save gas customers nearly $2.4 million (NPV) in avoided gas replacement costs while also delivering $2.4 million in avoided methane and carbon costs. The program would have a bill impact of $6.36 for non-participants over the first year of the program, after which the investment would be fully paid off.

Q. Please recap your recommendations for a Service Line NPA Program.

A. The Commission should require PSE to implement a Service Line NPA Program that offers customers impacted by a planned DIMP service line replacement or a foreseeable Public Improvement service line replacement over the MYRP a standard incentive of $16,500 (or an enhanced incentive of $18,500 for customers in Named Communities) to electrify rather than have their gas service replaced. To fund the program, the UTC should reduce PSE's requested DIMP budget by $3.3 million and approve an additional $240,000 to cover enhanced incentives in Named Communities and administrative costs. Program costs should be allocated to gas customers in the same way as DIMP costs, except they should be expensed instead of amortized. The Commission should adopt the Service Line NPA Program without delay as a commonsense next step in Washington's managed transition away from fossil gas.

III. ALTERNATIVE HEAT PILOTS

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I respond to PSE's proposals for two gas system decarbonization pilot programs: a thermal energy network (TEN) pilot proposed by Aaron A. August and a hydrogen blending pilot proposed by Michelle L. Vargo. I recommend approving the TEN pilot but not the hydrogen blending pilot because the former complies with applicable statutory requirements and presents a viable path toward decarbonizing parts of the gas distribution system, but the latter does not.

A. TEN Pilot

1) Background

Q. Please summarize PSE's thermal energy network pilot proposal.

A. PSE has proposed an $18.5 million Thermal Energy Network (TEN) pilot project at Seattle University (SU).[71] The proposed TEN would provide space heating, hot water, and cooling to numerous buildings on the SU campus, fully decarbonizing one building and significantly reducing natural gas consumption at ten others.[72] PSE estimates that the TEN would result in a 60% reduction in annual natural gas usage for the campus, which equates to approximately 1,800 tons per year of greenhouse gas savings, measured in carbon dioxide equivalent emissions.[73]

PSE proposes to competitively select a developer to design, build, own, and operate the TEN infrastructure, which would contract with PSE to provide the thermal energy service for a term of 20 to 30 years. PSE plans to recover 80% of the cost of the project from ratepayers as an O&M expense pursuant to its contract with the developer, beginning in 2028, and SU would cover the remaining 20%.[74] PSE is requesting authorization to recover approximately $2.6 million per year to cover its contractual payments to the developer, beginning in 2028 when the project becomes operational.

PSE's proposal is the first TEN cost recovery request to come before the Commission in a general rate case.[75]

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[71] PSE Exh. AAA-1T (Aaron A. August Opening Testimony) at 4:11.
[72] Exh. DAV-22 (PSE Response to Staff DR 173_Attachment A) at 4.
[73] *Id.* at 4-5; *see also* Exh. DAV-23 (PSE Response to Public Counsel DR 416 (R)) (quantifying gas savings).
[74] PSE Exh. AAA-1T (Aaron A. August Opening Testimony) at 47.
[75] Exh. DAV-24 (PSE Response to Public Counsel DR 410) at 6.

Q. What is TEN?

A. Thermal energy networks (TEN) use a system of pipes between buildings and heat pumps to provide space heating, cooling, and hot water by capturing waste heat from surrounding sources like the ground, water, or air.[76] Because they utilize "waste" heat, TENs provide highly efficient fossil fuel-free heating and cooling.[77] In Washington, TENs cannot rely on combustion to create thermal energy, except for emergency purposes.[78]

Q. Where are TENs appropriate and feasible?

A. TENs are most technically feasible in dense, mixed-use areas and neighborhoods located near sources of thermal energy such as industrial buildings, natural geothermal resources, or large bodies of water.[79] Studies have found that sites with "anchor tenants—large buildings or key neighborhood sites such as municipal buildings, hospitals, schools, and community centers—are particularly suitable to host a TEN, because those tenants provide large and stable energy demand for a TEN and generate necessary long-term revenue.[80]

Q. What are the benefits of TENs?

A. TENs have numerous environmental, health, and affordability benefits.[81] TENs generate significant climate and air quality benefits by replacing heating and cooling systems that rely on burning natural gas or delivered fuels, thereby reducing greenhouse gas emissions and localized air pollution.[82] TENs can also lead to lower and more stable energy bills, both for

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[76] *See* Partin, et al., *Thermal Energy Networks in the United States: Emerging Opportunities, Challenges, and Needs* (May 2025) at 7, available at https://www.transformativestrategies.net/_files/ugd/113511_4655e82411df46e1915b523483ccf044.pdf.
[77] *Id.*
[78] RCW 80.04.010(31).
[79] Bosworth et al., *Minnesota Thermal Energy Network Site Suitability Study* (Jan. 15, 2026) at 6, available at https://www.lrl.mn.gov/docs/2026/mandated/260051.pdf.
[80] *Id.*
[81] *See* Partin, et al., *supra* at 18–20.
[82] *Id.* at 18.

direct customers—because TENs have consistent, low operating costs throughout the year that aren't impacted by volatile fossil fuel price fluctuations—and for customers systemwide—because TENs reduce the demand for new fossil fuel infrastructure investments.[83]

TENs can also play a key role in facilitating a "just transition" from fossil fuels to clean energy systems. For instance, because TENs require relatively little electricity compared to conventional all-electric heating and cooling, implementing them where appropriate will reduce overall strain on the electric grid and free up capacity for other important electricity uses.[84] TENs can also provide the opportunity for entire neighborhoods to transition off fossil fuel infrastructure at the same time, allowing the gas infrastructure serving those neighborhoods to be retired and avoiding upward rate pressure from a smaller number of customers using that infrastructure as some customers electrify.[85] TENs can also provide valuable energy resiliency in communities by supplying local, reliable power during extreme weather events, which are ever worsening due to climate change and often lead to severe and dangerous disruptions to fossil fuel energy service.[86] Finally, TENs can smooth the gas transition by creating more skilled, clean energy jobs, as installing and maintaining TENs requires virtually identical skills as installing gas pipes.[87]

Q. Are there any examples of other comparable successful TENs projects?

A. Yes. Colorado Mesa University installed a TEN in 2008.[88] It is one of the largest geothermal systems in North America, and provides heating and cooling for 1.2 million square feet of academic and auxiliary buildings, connecting 16 buildings with 2.5 miles of central loop

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[83] *Id.* at 19.
[84] *Id.* at 19–20.
[85] *Id.*
[86] *Id.* at 19.
[87] *Id.* at 18–19.
[88] Colo. Mesa Univ., Sustainability Initiatives, *Geo-Grid System*, available at https://www.coloradomesa.edu/sustainability/initiatives/geo-grid.html.

pipe.[89] The TEN reduces Colorado Mesa University's carbon footprint 17,742 metric tons of CO2 per year, and saves the university $1.5 million in energy costs each year.[90] The TEN provides 90% of the energy required to operate the campus.[91] Colorado Mesa University is currently expanding its TEN to connect more campus buildings, and it is also exploring additional renewable energy integrations and potential opportunities to add nearby municipal buildings to its TEN.[92]

Q. What is the relevant statutory and regulatory background for PSE's TEN pilot proposal?

A. In March 2024, the Washington legislature passed Senate Bill 2131, which promotes the establishment of TENs in Washington, and authorizes gas and electric companies to deploy TENs within their service territories, provided they first seek the Commission's review and validation of cost assessments.[93] It establishes a TENs pilot program for gas utilities,[94] directs the Washington Department of Commerce to award grants for thermal energy network pilot projects,[95] and allows utilities to recover TENs costs through rate cases, if the Commission has validated the costs assessments for the TEN.[96]

In compliance with SB 2131, PSE sought and obtained the Commission's review and validation of cost assessments for the proposed TEN pilot in 2025.[97]

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[89] *Id.*
[90] *Id.*
[91] *Id.*
[92] *Id.*
[93] RCW 80.28.450(1).
[94] *Id*. at 80.28.460.
[95] *Id*. at 43.31.033.
[96] *Id*. at 80.28.450(2).
[97] UTC, Docket UG-250455, *Petition for the Intent to Deploy a Thermal Energy Network Pilot Project*, available at https://www.utc.wa.gov/casedocket/2025/250455/docsets.

2) Support for TEN Pilot

Q. Why do you support the TEN pilot proposal?

A. I support the TEN pilot proposal for several reasons. First, the pilot will generate direct environmental benefits by reducing natural gas consumption and associated emissions. Second, the pilot may lead to additional future benefits by expanding to nearby buildings and/or by facilitating broader deployment of TENs. Third, the pilot is the result of prudent and strategic planning that comports with statutory requirements.

Q. Please elaborate on the pilot's direct environmental benefits.

A. As referenced above, the pilot will reduce greenhouse gas emissions by approximately 1,800 tons per year.[98] This reduction in carbon emissions will further statewide climate goals and help SU meet its compliance obligations under the Clean Buildings Performance Standard (CBPS) and the Seattle Building Emissions Performance Standard (BEPS). Further, by replacing natural gas with clean energy, the pilot will improve localized air quality by eliminating on-site combustion-related emissions of toxic pollutants like nitrogen oxides, carbon monoxide, and particulate matter.[99] While these site-specific reductions are relatively small compared to overall emissions, they are nevertheless a meaningful step in the clean energy transition.

Q. Please elaborate on the pilot's potential future benefits.

A. The pilot is likely to lead to additional emissions reductions in the future due to its potential to expand and scale. The TEN has a modular design and oversized main piping, to enable PSE to increase the existing system's capacity for heating and cooling, or further expand the system to

[98] Exh. DAV-22 (PSE Response to Staff DR 173_Attachment A) at 4–5.
[99] Exh. DAV-25 (PSE Response to Public Counsel DR 429) at 2.

serve additional buildings.[100] It is thus well-suited to serve as an "anchor" for an expanded TEN that encompasses nearby buildings, potentially including four large nearby healthcare centers.[101]

Further, the pilot may serve as a helpful demonstration that TENs can be operated effectively in Washington, encourage additional pilot projects and TENs programs, and provide insight and guidance for streamlining TENs implementation. Prompt build out of TENs in appropriate locations will generate systemwide benefits as described above—through lowering energy costs, providing green jobs, promoting energy resiliency, reducing greenhouse gas and other toxic air emissions, and improving public health.

Q. Please elaborate on the pilot's basis in strategic planning.

A. The TEN pilot proposal is grounded in strategic planning and therefore represents a reasonable and prudent investment—in stark contrast to the hydrogen pilot, as explained further in the next section. PSE complied with applicable statutory requirements, including by seeking the Commission's review and validation of costs in Docket UG-250455 and proposing reasonable specific metrics to evaluate a pilot TEN project.[102] In selecting a pilot location, PSE generated a list with over 25 potential TENs projects, and considered factors like energy density, proximity of buildings, and having an engaged customer as an "anchor tenant," to narrow the site selection and choose SU as the ultimate candidate.[103]

The TEN pilot also plays a clearer role in a viable decarbonization strategy than the hydrogen pilot. As described earlier, appropriately deployed TENs can be crucial components

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[100] *See* Exh. DAV-26 (PSE Response to Staff DR 181_Attachment A) at D1 (describing the modular central plant concept).
[101] PSE Exh. AAA-1T (Aaron A. August Opening Testimony) at 50–51.
[102] RCW 80.28.460(6); *see* Exh. DAV-22 (PSE Response to Staff DR 173_Attachment A) at 15.
[103] Exh. DAV-22 (PSE Response to Staff DR 173_Attachment A) at 3.

in facilitating the energy system transition away from fossil fuels, because they provide clean heating and cooling services without burdening the electric grid. TENs are also compatible with a wider range of decarbonization pathways; unlike hydrogen blending, TEN pilots' ability to facilitate emission reductions does not depend on the emergence of a clean hydrogen production industry that does not yet exist or continued reliance on a gas distribution pipeline system. Further, in reducing natural gas usage, TENs also free up gas system capacity and minimize the need for further investment in gas infrastructure.

Further, in the TEN pilot proposal, PSE has provided more mature cost estimates from experienced engineers,[104] a concrete project design with an eye toward streamlining future expansion of the TEN,[105] and estimated emission reductions based on reasonable, context-specific modeling.[106] Based on PSE's estimate that the TEN pilot would save approximately 1,800 tons per year of carbon dioxide equivalent emissions and expectation that the yearly contract payments to the TEN developer will be approximately 2.6 million dollars, it's possible to calculate the estimated cost of avoided emissions as one metric by which to evaluate the pilot. PSE also calculated, using its Gas Conservation Cost Effectiveness framework, that the projected gas savings from the pilot would have an estimated value of approximately $12.8 million.[107]

3) Considerations regarding cost allocation

Q. Has PSE addressed the allocation of costs and risk between PSE customers and SU?

A. Yes. As mentioned above, ratepayers would cover 80% of the pilot costs and SU would cover the remaining 20%. PSE explained that this arrangement targets SU's payments to remain

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[104] *See id.* at 5.
[105] *See* Exh. DAV-26 (PSE Response to Staff DR 181_Attachment A) at D1.
[106] *See* Exh. DAV-22 (PSE Response to Staff DR 173_Attachment A) at 5.
[107] Exh. DAV-27 (PSE Response to Public Counsel DR 76) at 2.

similar to what SU currently pays for the gas service displaced by the TEN pilot project, to ensure an economic value proposition to SU.[108] PSE has indicated that if project costs are substantially higher than currently projected, PSE would renegotiate pricing with SU, likely requesting an increase in the percentage of costs recovered from gas base rates.[109] However, if the project costs are substantially lower than $18.5 million, it would maintain the same 80/20 split between SU and ratepayers, which would both benefit from the lower costs.[110]

Q. What is your opinion on PSE's proposed cost and risk allocation between PSE customers and SU?

A. In my opinion, PSE's current rate recovery request for this pilot project, based on the 80/20 split arrangement, is reasonable. However, if costs are higher than expected and PSE wants to recover additional costs, it would need to provide sufficient justification for any requested increase in a future proceeding.

If costs end up being lower than expected, PSE should consider passing savings along to ratepayers rather than splitting savings between ratepayers and SU. Given that the goal of the cost allocation arrangement is to keep SU's bills roughly the same as current bills and SU is willing to participate in the pilot on those terms, PSE could structure its contract with SU to keep its contribution the same even if project costs are lower and let ratepayers realize more of the savings—particularly since ratepayers would bear the majority of project costs under the agreed upon arrangement.

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[108] PSE Exh. AAA-1T (Aaron A. August Opening Testimony) at 52.
[109] *Id*. at 53–54.
[110] *Id.*

4) Considerations for pilot implementation and future TENs projects

Q. What are your recommendations for implementing the TENs pilot?

A. Given that the pilot is still in early stages, PSE should continue to prioritize pilot design that will make future expansions and capacity improvements feasible and streamlined, including by continuing to investigate adding thermal energy storage, and maximize further decarbonization opportunities. I urge PSE to take steps to increase the TEN's capacity to serve SU's heating and cooling needs and expand the TEN to other nearby candidate buildings as soon as practicable.

I also recommend that PSE pursue another TEN at the previously-proposed Maleng Regional Justice Center in a future proceeding. This project could bring the benefits of TENs to Named Communities, helping promote equitable gas system decarbonization.[111] Finally, I also urge PSE to investigate and, as appropriate, propose neighborhood-wide utility scale TENs projects in future proceedings.[112]

Q. Please summarize your recommendations with respect to PSE's proposed TEN pilot.

A. I recommend that the UTC approve the proposed pilot and encourage PSE to pursue additional TENs pilots in the future, including the Maleng Regional Justice Center project.

[111] Exh. DAV-22 (PSE Response to Staff DR 173_Attachment A).
[112] Camargo et al., *The Future of Heat: Thermal Energy Networks as an Evolutionary Path for Gas Utilities Toward a Safe, Equitable, Just Energy Transition*; available at https://buildingdecarb.org/wp-content/uploads/The-Future-of-Heat-Thermal-Energy-Networks-as-an-Evolutionary-Path-for-Gas-Utilities-Toward-a-Safe-Equitable-Just-Energy-Transition.pdf.

B. Hydrogen Blending Pilot

1) Background

Q. Please summarize PSE's hydrogen blending pilot proposal.

A. PSE has proposed a $3.4 million hydrogen blending pilot that would blend up to 5% hydrogen into a portion of PSE's gas distribution system serving approximately 500 customers.[113] PSE plans to procure hydrogen from regional suppliers, rather than produce hydrogen for the pilot.

Q. Has PSE proposed any other alternative fuel investments in this rate case?

A. Not to my knowledge. PSE Witness Steuerwalt mentions that PSE procured 3.5 million Btus of biogas (or "renewable natural gas") in 2025.[114] However, PSE confirmed in a discovery response that it is not seeking cost recovery for any biogas-related costs in this rate case.[115]

Q. Has PSE proposed programs similar to its hydrogen blending pilot in the past?

A. Yes. In PSE's 2024 general rate case, the Company proposed a $3 million "alternative fuels readiness program" to investigate the use of renewable natural gas and hydrogen blends in its system. The $3.4 million hydrogen blending pilot proposed in this rate case replaces the alternative fuels readiness program.[116] The JEAs recommended rejection of the alternative fuels readiness program in 2024, in part because PSE did not provide basic details for the program such as how the pilots could help PSE decarbonize its gas system. The Commission declined to approve the program, finding that PSE had not established why its costs should be passed to ratepayers, but took "no stance on the need for or feasibility of RNG and hydrogen."[117]

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[113] PSE Exh. MLV-1T (Michelle L. Vargo Opening Testimony) at 106–109; PSE Exh. MLV-12 (Natural Gas Reliability and Resiliency Investments) at 19.
[114] PSE Exh. MS-1T (Matt Steuerwalt Opening Testimony) at 23:14–15.
[115] Exh. DAV-28 (PSE Response to JEA DR 75); *see also* Exh. DAV-29 (PSE Response to JEA DR 77).
[116] PSE Exh. MLV-12 (Natural Gas Reliability and Resiliency Investments) at 17 ("This [Corporate Spending Authorization] replaces the programmatic CSA of alternative fuels readiness.").
[117] UTC, Docket No. UE-240004, Order 09/07 at ¶ 468.

Q. What is the relevant statutory and regulatory background for PSE's current hydrogen blending pilot proposal?

A. State government entities such as the State Legislature and Department of Commerce have identified a limited role for hydrogen in decarbonizing certain sectors of Washington's economy. They have focused on the use of renewable hydrogen and green electrolytic hydrogen for heavy industry and transportation, rather than blending hydrogen into gas distribution systems.

For example, in 2022 the State Legislature found in Substitute Senate Bill 5910 that hydrogen is "a valuable decarbonization tool when used in sectors such as marine, aviation, steel, aluminum, and cement, as well as surface transportation including heavy duty vehicles, such as transit, trucking, and drayage equipment."[118]

The Department of Commerce's 2021 State Energy Strategy found that an approach of electrifying buildings "appears to serve the state's consumers and businesses better than one where non-fossil gas is manufactured and delivered by pipeline to end users."[119] The State Energy Strategy did identify an interim "opportunity in the near term for the [natural gas] industry to pursue actions consistent with its preferred approach" of decarbonizing pipeline fuels, but stated that these actions should "achieve near-term reductions in greenhouse gas emissions" and aim to "improv[e] the financial viability of gas as a non-emitting energy form."[120] Gas utilities have not made meaningful progress toward either of these two objectives since the State Energy Strategy was published in late 2020, and the U.S. Department of Energy has cancelled funding for the Pacific Northwest Hydrogen Hub.

[118] Wash. Laws of 2022, Chapter 292 § 1(1).
[119] Wash. Dep't of Com., *Washington 2021 State Energy Strategy* (Dec. 2020) at 82, available at https://deptofcommerce.app.box.com/s/zsbjvf0nato9q7dk3t7jjh0vjbd4iqof.
[120] *Id.*

Finally, the UTC's Energy Decarbonization Pathways report found that even in the "Alternative Fuels" scenario that was "designed to replace fossil fuels with renewable or zero emission fuels such as renewable natural gas and hydrogen,"[121] hydrogen use was focused in the industrial sector and met only a tiny fraction of residential and commercial energy use. In this scenario, hydrogen met only 1% of residential demand by 2050 (compared to 53% from grid electricity) and 3% of commercial demand (compared to 81% from grid electricity).[122]

Q. Are you opposed to the use of hydrogen as a decarbonization strategy?

A. No, I understand hydrogen could play a limited but important role in pathways to fully decarbonize the economy, specifically for the most challenging sectors to electrify like heavy industry. However, because renewable hydrogen production will remain costly and energy-intensive and there are major challenges and limitations with delivering hydrogen through gas distribution systems, hydrogen blending is not a viable gas system decarbonization strategy.

2) General Issues with Hydrogen Blending

Q. Please describe your general concerns about hydrogen blending as a gas distribution system decarbonization strategy.

A. I have four major concerns.

First, hydrogen has limited availability and high costs. Clean hydrogen is not generally commercially available in Washington. An analysis of 32 independent studies found that the use of hydrogen for heating had significantly higher costs than alternative technologies like

[121] *Id.* at 130.
[122] Calculated from UTC's Energy Decarbonization Pathways Report Data, available at https://dbzys6kmq0jpb.cloudfront.net/washington-data/washington_output.xlsx.

heat pumps, concluding that none of the 32 studies supported the widespread use of hydrogen for heating.[123]

Second, hydrogen blending presents safety and compatibility issues with gas distribution systems and gas appliances, especially at higher blending ratios. In 2024, PSE estimated that the technical limit for blending hydrogen into the gas distribution system is 15% by volume, which equates to 5% by energy content.[124] A study prepared for the California Public Utilities Commission suggested a systemwide blending limit of 5% by volume (2% by energy) due to potential leaks from vintage pipe (hydrogen is a smaller molecule than methane) and the need to modify end-use appliances.[125] Similarly, the National Regulatory Research Institute (NRRI) found that hydrogen blends above 5% by volume can result in unsafe ignition conditions for home appliances such as water heaters and stoves.[126]

Third, hydrogen lacks a viable pathway to avoiding a significant amount of gas system emissions, due to the availability, cost, and system compatibility issues described above. Moreover, in the last five years the clean hydrogen market has developed more slowly than the State Energy Strategy anticipated, casting further doubt on hydrogen's potential role as a near-term strategy for decarbonizing pipeline fuels on the way to electrification of Washington's residential and commercial sectors.

Fourth and finally, burning hydrogen blends in homes and businesses can increase emissions of nitrogen oxides (NOx) due to hydrogen's higher combustion temperature. A

[123] Jan Rosenow, *Is Heating Homes with Hydrogen All but a Pipe Dream? An Evidence Review*, 6 Joule Commentary 2225 (Oct. 19, 2022), available at https://www.sciencedirect.com/science/article/pii/S2542435122004160.
[124] UTC, Docket No. UE-240004, Exh. BTC-1T (Bradley Cebulko Response Testimony) at 38:1–6.
[125] A. Raju et al., *Hydrogen Blending Impacts Study* (July 18, 2022), available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.
[126] Jeff Loiter et al., *Green Hydrogen for Pipeline Injection in LDC Infrastructure*, the National Regulatory Research Institute (Oct. 12, 2022, corrected version Aug. 31, 2023), available at https://drive.google.com/file/d/1zC37DW0_uJBpjK9MjXHeNH3AzZNmpxyi/view.

meta-analysis of 14 studies found that a 5% blend of hydrogen increased NOx emissions by 8% on average.[127] This is especially concerning because NOx is one of the main indoor pollutants of concern associated with appliances like gas stoves.[128]

Q. Have other utility commissions expressed similar concerns about hydrogen blending?

A. Yes. Similar concerns led the Colorado Public Utilities Commission to reject a hydrogen blending proposal from the state's largest gas utility. The Colorado PUC was concerned that the utility had offered no "realistic vision of the role that green hydrogen would or could play as a safe and cost-effective solution on the system at large,"[129] and found it unclear how "the demonstration project would be helpful or a prudent use of ratepayer dollars, in pursuit of a deeply decarbonized future system."[130] Likewise, the Massachusetts Department of Public Utilities declined to authorize the use of ratepayer funds for hydrogen blending pilots due to "uncertain[ty] about the viability of . . . hydrogen technologies and their potential as economical long-term solutions for ratepayers."[131]

Q. Does PSE's hydrogen blending pilot proposal address any of these general concerns about hydrogen blending?

A. No. As I discuss below, the pilot proposal does not improve the financial viability of clean hydrogen, and PSE cannot even say whether the pilot will reduce emissions or at what cost. The pilot would not evaluate system compatibility with blends above 5% hydrogen. And PSE

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[127] Madeline L. Wright & Alastair C. Lewis, *Emissions of NOx from Blending of Hydrogen and Natural Gas in Space Heating Boilers* (May 31, 2022), Elementa, 10 Science of the Anthropocene 1, available at https://doi.org/10.1525/elementa.2021.00114.
[128] *See* Andee Krasner & Barbara Gottieb, *Hydrogen Pipe Dreams: Why Burning Hydrogen in Buildings is Bad For Climate and Health*, Physicians for Social Responsibility (June 2022) at 15, available at https://psr.org/wp-content/uploads/2022/07/hydrogen-pipe-dreams.pdf.
[129] Colo. Pub. Util. Comm'n Decision No. C24-0397 at 82.
[130] *Id.*
[131] Mass. Dep't Pub. Util. 20-80-B, *Order on Regulatory Principles and Framework* at 79.

has not proposed an adequate protocol for monitoring indoor air pollution in pilot participants' homes.

3) Specific Concerns with PSE's Hydrogen Blending Proposal

Q. Do you have any specific concerns about PSE's hydrogen blending pilot proposal?

A. Yes. I have four major concerns with PSE's hydrogen blending pilot proposal:

1. The proposal does not answer basic questions about how PSE will procure hydrogen for the pilot, how much the hydrogen will cost, and what its environmental attributes will be.
2. The proposal does not answer basic questions about the pilot design, community selection process, and safety protocols.
3. The proposal does not include reliable, reasonably mature cost estimates.
4. The proposal does not meet requirements applicable to hydrogen blending projects, including the requirements of RCW 80.28.435.

i. Hydrogen Procurement

Q. Please elaborate on your first concern, that PSE's hydrogen blending pilot proposal does not answer basic questions about how PSE will procure hydrogen for the pilot.

A. PSE states that it will purchase the hydrogen for its proposed pilot "from regional suppliers."[132] However, PSE has not been able to identify any such regional suppliers who could supply hydrogen for the pilot.[133] This raises serious concerns about the availability, emissions intensity, and cost of hydrogen that could be used in the pilot.

[132] PSE Exh. MLV-12 (Natural Gas Reliability and Resiliency Investments) at 18.
[133] Exh. DAV-30 (PSE Response to JEA DR 81) at § (a).

Q. Please describe your concern about the availability of hydrogen for PSE's proposed pilot.

A. PSE has not provided any evidence indicating that it will be able to procure hydrogen for the pilot at all. PSE admits that it "has not identified potential hydrogen supply sources" for the pilot.[134]

The only potential hydrogen producer mentioned in PSE's proposal is the Pacific Northwest Hydrogen Hub.[135] But as PSE admits, the Department of Energy terminated its financial award for this hydrogen hub in October 2025, and some project partners who had been working on the hub have paused development activities.[136]

Even if hydrogen hub funding were available, PSE acknowledges that "the Pacific Northwest Hydrogen Association has not indicated any intent to provide hydrogen specifically for gas distribution system blending" because it is focused on other applications such as "freight transportation, industrial applications … and peak power generation, not blending into natural gas distribution systems."[137] These other applications will presumably be potential buyers of the hydrogen produced by any regional supplier, and PSE has not addressed how this competition will affect the availability—let alone the price—of hydrogen for its pilot.

This all raises serious concerns about the prudency of investing in infrastructure to deliver a fuel that there is no reason to believe PSE can even procure.

Q. Please describe your concern about the emissions intensity of hydrogen used in the pilot.

A. PSE has not committed to using hydrogen that meets any greenhouse gas intensity standard, or that meets the statutory definition of green electrolytic hydrogen under RCW 43.330.560(2) or

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[134] *Id*. at § (d).
[135] PSE Exh. MLV-12 (Natural Gas Reliability and Resiliency Investments) at 14 (stating that the Pacific Northwest "has been awarded hydrogen hub funding through the Department of Energy's Office of Clean Energy Demonstrations (OCED)").
[136] Exh. DAV-31 (PSE Response to JEA DR 78) at § (a).
[137] *Id*. at § (b).

renewable hydrogen under RCW 54.04.190(6)(c).[138] Because hydrogen can have a substantially higher emissions intensity than natural gas if it is produced through processes other than electrolysis powered by renewable energy,[139] this means that PSE's pilot could increase emissions, rather than decrease them.

PSE has not analyzed whether and to what extent the pilot would reduce emissions, or proposed any plans or process to do so in the future.[140] If the pilot does increase PSE's emissions, PSE has not identified any method for evaluating the amount of this increase or retiring the corresponding number of CCA allowances.

PSE states that the pilot's "primary objective is to evaluate infrastructure compatibility, operational integration, and community engagement, not to demonstrate emissions reductions from a specific hydrogen production pathway."[141] In my opinion, this risks imprudent investment in one element of a decarbonization strategy (hydrogen blending) without adequate assurance that another essential element of that strategy (renewable hydrogen availability) will be addressed. Requiring the use of renewable hydrogen or green electrolytic hydrogen for any gas distribution system blending projects would ensure that they do not put the cart before the horse, and that they align with the State Legislature's intent in supporting renewable and green electrolytic hydrogen.[142]

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[138] Exh. DAV-30 (PSE Response to JEA DR 81) at §§ (b)–(c).
[139] *See*, e.g., Alice Bennett & Andre Cabrera Serrenho, *A Systematic Comparison of the Energy and Emissions Intensity of Hydrogen Production Pathways in the United Kingdom*, 89 Int. J. Hydrogen Energy 364, 371 (2024) ("In many cases, such as hydrogen produced via steam methane reforming with low CCS (52%), the emissions intensity exceeds that of natural gas combustion."). Accessible at https://doi.org/10.1016/j.ijhydene.2024.09.170.
[140] Exh. DAV-30 (PSE Response to JEA DR 81) at §§ (d)–(e).
[141] *Id*. at § (b).
[142] Wash. Laws of 2022, Chap. 292 § 1(1) –(2) ("The legislature finds that while hydrogen fuel has been used in a variety of applications in the state, the source of hydrogen has been derived from fossil fuel feedstocks, such as natural gas. … (2) The legislature further finds that the use of renewable hydrogen and hydrogen produced from carbon-free feedstocks through electrolysis is an essential tool to a clean energy ecosystem and emissions reduction for challenging infrastructure needs.").

To the extent PSE aims to promote renewable hydrogen production by demonstrating market demand for it through a blending pilot, this is not an appropriate use of ratepayer dollars. The industrial and freight transport sectors are most likely to benefit from the development of a renewable hydrogen market, especially during such a market's early years. Using gas system blending projects to promote development of that market would effectively use ratepayer dollars to subsidize decarbonization of industry and freight transport—laudable projects, to be sure, but not ones that PSE's gas customers should have to pay for.

Q. Please describe your concern about the cost of hydrogen used in the pilot.

A. PSE cannot reasonably estimate the cost of procuring hydrogen for its pilot without any information about potential hydrogen sources. PSE has not estimated the expected cost per unit of hydrogen for its proposed pilot.[143]

This makes it impossible to assess whether the costs of the proposed hydrogen procurement are reasonable and prudent by comparing them to the costs of hydrogen used in the existing blending pilots cited by PSE.[144] It also casts doubt on PSE's overall project cost estimate, which does not include an estimate of hydrogen commodity costs' contribution to total project costs or an analysis of how total project costs would be affected if hydrogen costs are higher or lower than expected.[145]

And because PSE has no estimate of the emissions intensity or net emissions impact of hydrogen used in the pilot, it cannot estimate the cost per ton of emission reductions from its proposed hydrogen blending. Indeed, PSE admits it has not developed any such estimate.[146]

[143] Exh. DAV-32 (PSE Response to JEA DR 82) at § (e).
[144] *Id*. ("…nor has [PSE] compared such costs to those of other pilot projects.").
[145] Exh. DAV-32 (PSE Response to JEA DR 82) at § (c).
[146] Exh. DAV-30 (PSE Response to JEA DR 81) at § (f).

This makes it impossible to compare the cost-effectiveness of hydrogen blending to other gas system decarbonization strategies, such as electrification.

ii. Pilot Design

Q. Please elaborate on your second concern, that PSE's hydrogen blending pilot proposal does not answer basic questions about the pilot design, community selection process, and safety protocols.

A. PSE's proposal does not include detail about several key elements of the project design and needed equipment, such as the size of the blending skid, what infrastructure upgrades are needed to blend the hydrogen, how much hydrogen will be needed for the project, and what kinds of measurement equipment will be used.

While PSE's planned site selection process and safety standards include some promising features such as co-selection with the affected community, preferred distribution system characteristics for the pilot, and courtesy pre-inspections of customer appliances, these are generally described at a high level and would need to be developed to ensure the pilot does not compromise participants' health and safety.

Importantly, PSE does not have a plan to monitor indoor air pollution, including nitrogen oxides (NOx) in affected customers' homes during the pilot. In a discovery response, PSE indicated that it only plans to inspect NOx emissions during its courtesy pre-inspections of customer appliances and targeted post-blend inspections.[147] PSE has not developed a plan to monitor emissions or ambient NOx levels in participants' homes during the pilot, or to evaluate any indoor air pollution-related adverse health effects participants may experience.[148] Nor has PSE outlined a protocol for informing participants about the potential health effects of

[147] Exh. DAV-32 (PSE Response to JEA DR 82) at §§ (a)–(b).
[148] *Id*. at §§ (a)–(c).

hydrogen blending on NOx emissions.[149] These are concerning omissions, because NOx is one of the main indoor air pollutants of concern associated with equipment like gas stoves, and hydrogen blending can increase indoor NOx pollution as described above.

iii. Cost Estimates

Q. Please elaborate on your third concern, that PSE's hydrogen blending pilot proposal does not include reliable, reasonably mature cost estimates.

A. PSE's cost estimates include very little detail, and PSE has made inconsistent statements about the estimates and the methods it used to develop them.

PSE estimates that the project will have $1.4 million in capital costs and $2 million in O&M costs,[150] but its Corporate Spending Authorization only appears to account for $1,066,375 in project costs.[151]

PSE was not able to identify any materials or analyses supporting its cost estimates other than MLV-12,[152] which includes just one paragraph addressing cost estimates. In that paragraph, PSE says its budget estimate includes "customer appliance inspections, infrastructure upgrades and blending skid, hydrogen supply, and necessary tools and measurement equipment,"[153] but it could not provide estimates for how much any of these components will cost.[154] PSE's inability to account for the costs of project components is consistent with its inability to identify a source of hydrogen for the project and its undeveloped project design, discussed above.

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[149] *Id*. at § (d).
[150] PSE Exh. MLV-12 (Natural Gas Reliability and Resiliency Investments) at 19.
[151] *Id*. at 13.
[152] Exh. DAV-32 (PSE Response to JEA DR 82) at § (b).
[153] PSE Exh. MLV-12 (Natural Gas Reliability and Resiliency Investments) at 19.
[154] Exh. DAV-32 (PSE Response to JEA DR 82) at § (c) ("A more granular breakdown by individual equipment component is not available at this stage of project development and will be developed during the Design phase (Q2 2028 – Q1 2029).").

PSE said in a discovery response that one factor informing its budget estimate was "PSE's review of prior industry hydrogen blending pilots," but elsewhere said that a direct cost comparison to these other pilots "is not meaningful at this stage for several reasons," including the preliminary nature of PSE's estimates and material differences in scope, geographic and regulatory context, and project components.[155]

I am concerned that PSE's very preliminary cost estimates are not sufficient to ensure that the final project costs will be reasonable.

iv. Compliance with RCW 80.28.435.

Q. Please elaborate on your fourth concern, that PSE's hydrogen blending pilot proposal does not address the requirements of RCW 80.28.435.

A. RCW 80.28.435 establishes requirements that gas utilities must meet "prior to replacing natural gas with renewable hydrogen or green electrolytic hydrogen to serve customers." A gas utility must file a notice with the Commission establishing that it has received all necessary siting and permitting approvals, and addressing (1) whether the use of clean electricity to produce hydrogen is consistent with the company's most recent integrated resource plan, (2) potential impacts to grid reliability, and (3) standards, including safety standards, for blending green electrolytic hydrogen and renewable hydrogen into natural gas distribution infrastructure.

PSE admits that it has not filed a notice under RCW 80.28.435, and that it has not received siting or permitting approvals for the hydrogen blending pilot.[156] This stands in notable contrast to PSE's TEN pilot, for which PSE has already sought and received the necessary Commission approval as discussed above.

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[155] *Id*. at §§ (a), (d).
[156] Exh. DAV-33 (PSE Response to JEA DR 84) at § (a).

Q. What reasons does PSE give for failing to file the required notice?

A. In a discovery response, PSE suggested two explanations for its failure to file the notice. First, PSE says it "intends to file the required notice and obtain all necessary approvals before commencing hydrogen blending operations."[157] Second, PSE suggests that it only needs to meet the requirements of RCW 80.28.435 "to the extent that the hydrogen procured for the pilot meets the definitions of 'renewable hydrogen' or 'green electrolytic hydrogen' under applicable law."[158]

Q. Do you have concerns about PSE's rationale?

A. Yes. I am concerned about PSE's first explanation because it suggests that PSE plans to secure approval to use customer funds on the project now, and determine whether and how to meet applicable statutory requirements after the project is underway. If the project is not able to meet applicable requirements, it will not be able to go into service and any approved costs of the project will not be prudently incurred. This creates significant risk that could be avoided if PSE secured the necessary approvals first and sought cost recovery second. It also appears inconsistent with the requirement in RCW 80.28.435(2) for the Commission to consider "the information contained in the notice," among other information, "when making a determination on a company's request for approval of any tariff related to the use of green electrolytic hydrogen or renewable hydrogen as a replacement for natural gas." Insofar as PSE has proposed to update its base rate tariffs to recover the costs of its hydrogen blending pilot, it appears to be requesting approval of a tariff "related to the use" of hydrogen. RCW 80.28.435(2) appears to require that PSE file the required notice before the Commission can make a determination on such a request.

[157] *Id.*
[158] *Id.*

I am concerned about PSE's second explanation because it suggests that PSE thinks it can avoid the requirements of RCW 80.28.435 by blending other forms of hydrogen with higher emissions intensities into its gas system. I am not aware of any provision of Washington law allowing gas utilities to blend gray hydrogen or other forms of dirty hydrogen into their systems, and while I am not a lawyer, I understand RCW 80.28.435 to exclusively authorize blending renewable and green electrolytic hydrogen. Moreover, most of RCW 80.28.435's requirements are equally necessary to ensure safe and successful blending regardless of the type of hydrogen being used, such as securing necessary siting and permitting approvals, establishing safety standards for blending hydrogen into natural gas distribution infrastructure, and obtaining Commission approval prior to initiating blending.

Q. Based on your analysis, what do you recommend with respect to PSE's hydrogen blending pilot proposal?

A. I recommend that the UTC deny PSE's hydrogen blending pilot proposal. I recommend declining to approve any hydrogen blending projects or grant recovery of associated costs, at least until PSE has identified a source of renewable or green electrolytic hydrogen for the project, developed reasonably mature cost and emissions estimates that enable calculation of a cost per ton of GHG abatement, and met the requirements of RCW 80.28.435. If the Commission were to approve PSE's proposed hydrogen blending project, I would recommend only provisionally approving the project and requiring PSE to demonstrate that it has met the requirements of RCW 80.28.435 before incurring significant project costs.

IV. <u>CONCLUSION</u>

Q. Please summarize your recommendations to the Commission.

A. I recommend that the Commission: (1) require PSE to implement the Service Line NPA Program described in this testimony, (2) approve PSE's proposed TENs Pilot, and (3) reject PSE's hydrogen blending pilot. This suite of recommendations will meaningfully advance Washington's climate goals while supporting a managed and cost-effective transition away from gas—delivering significant benefits to all PSE customers.

Q. Does this conclude your testimony?

A. Yes.