EXH. DJL-3
DOCKETS UE-240004/UG-240005
2024 PSE GENERAL RATE CASE
WITNESS: DAVID J. LANDERS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	Docket UE-240004 Docket UG-240005

SECOND EXHIBIT (NONCONFIDENTIAL) TO THE PREFILED DIRECT TESTIMONY OF

DAVID J. LANDERS

ON BEHALF OF PUGET SOUND ENERGY

FEBRUARY 15, 2024

PUGET SOUND ENERGY

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I. CUSTOMER AND PUBLIC SAFETY

A. Overview

Q. Please briefly describe Puget Sound Energy's ("PSE") customer and public safety investments presented in this case.

A. Customer and public safety is PSE's highest priority and is at the forefront of all work performed on PSE's electric and gas systems. It is also the primary driver of key activities including emergency repair, public improvement projects to resolve conflicts between transportation infrastructure projects and PSE's energy delivery system, and planned maintenance programs. Investments in new or modified infrastructure are designed and constructed in accordance with PSE standards and applicable state and federal safety standards.

Q. Please provide PSE's planned customer and public safety capital investments over the rate period presented in this case.

A. Table 1 provides planned capital investments from January 1, 2025 through December 31, 2026, which are estimated based on historic trends and programmatic plans.

Table 1: Summary of total customer and public safety capital investments by year.

Customer and public safety ($ Millions)	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Electric Capital investment	205.8	210.8
Gas Capital investment	160.8	165.5
Common Capital Investment	2.0	1.6

Additionally, there is incremental operations and maintenance ("O&M") expense related to capital investment ("OMRC") associated with the above periods totaling approximately $18 million over the two years. An additional direct O&M spend of around $39 million is expected for customer and public safety operations activities over this period.

Q. Are there O&M cost reductions that are expected to result from these program investments?

A. No significant decrease in O&M costs are expected from this category of work. New equipment installed during an emergency repair or a planned project to correct an operational concern will have continuing maintenance requirements. While some newer equipment may offer improved reliability and require less frequent maintenance intervals, with advancing technology other equipment is becoming more complex, requiring increasing levels of maintenance. In total, emergency replacements are not expected to provide a net reduction in O&M expenses. Relative to public improvement projects, PSE reviews project locations and, where possible, combines the relocation work with planned programmatic replacements or upgrades, which can more cost effectively reduce poorer condition asset populations and avoid potential future outages. However, while PSE facilities are often replaced in association with public improvement projects, the O&M benefits are limited. In some instances, public improvement work may directly increase O&M expense, particularly in instances where PSE negotiates and pays for redesign of a jurisdictional project to avoid relocation of electric and natural gas infrastructure. The additional O&M expense for supporting redesign is selected in lieu of a significantly higher capital investment for relocation of electric or natural gas infrastructure.

Q. Please describe cost controls employed to efficiently deploy capital investments.

A. Because of the immediate need to respond, emergency repair investments are generally like-kind replacements in accordance with established procedures for repairs and completion. These procedures are defined in 14 gas design, construction, and operating field procedures and standards, and 21 electric design and construction work practices. PSE's service provider contract pricing and oversight of the work provide cost control for immediate emergency response and unplanned replacement work. The investment level will vary based on the number of events and degree of damage that must be repaired during a given interval of time, with budget planning based on observed and predicted trends.

Cost controls deployed by PSE for public improvement and planned maintenance investments follow the general approach discussed in the Prefiled Direct Testimony of Roque B. Bamba, Exh. RBB-1T. A project manager is assigned who manages the project from inception through closeout, driving the schedule, managing budgets, and coordinating construction and design activities with both internal and external team members. Additional cost controls exist through fixed unitized pricing of established construction contracts.

B. Equity

Q. Please describe how PSE has considered equity in customer and public safety investments.

A. While PSE has little control regarding location of emergencies, public improvement, or required maintenance, PSE recognizes that decisions in how PSE responds to these events or prioritizes actions can help to advance energy equity. Where conditions allow, system repairs and restoration are prioritized in named communities.

C. Emergency Repair

Q. Please describe PSE's emergency repair investments and core objectives and priorities.

A. Emergency repairs, or "corrective maintenance," includes the repair and/or replacement of failed or compromised infrastructure, such as replacing a pole that has been damaged or an inspection indicating imminent failure could occur, repairing storm damage, repairing a meter set that has been damaged or repairing a leak that requires extensive pipe replacement. The core objectives of this work and investments are to respond quickly to resolve immediate and imminent safety concerns and return the infrastructure to sound function for the health of the system. Emergency repairs are the highest priority for PSE, including priority over discretionary and other non-discretionary work. These investments are supported by Corporate Spending Authorization ("CSA") requests provided for electric and gas as provided in Appendix A and B, respectively. CSAs provide project background, statement of need, scope, benefits, cost estimate, alternatives, and funding risk.

Q. Please provide PSE's planned emergency repair capital investments over the rate period presented in this case.

A. Table 2 provides the planned capital investments from January 1, 2025 through December 31, 2026, which are estimated based on historic trends and plans.

Table 2: Summary of emergency repair capital investments by year.

Emergency repair	**Rate Plan Year 1 2025**	**Rate Plan Year 2 2026**
Electric Capital investment ($ Millions)	82.3	81.7
Electric Outages addressed (#)	approximately 12,000	
Gas Capital investment ($ Millions)	28.0	28.6
Gas Leaks addressed (#)	1,000 – 1,200	

Additionally, there is incremental OMRC associated with the above capital investments required for emergency repair totaling $6 to $8 million over the two-year multiyear rate plan period. Direct O&M charges totaling $4 million for natural gas system repairs are also expected over the two years.

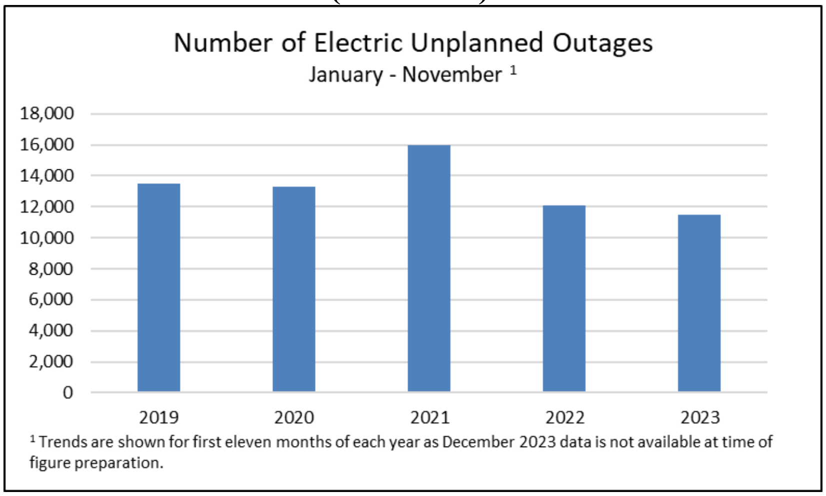
Q. Please describe the work completed and anticipated through the end of the rate plan.

A. PSE anticipates outages will continue in the range of approximately 12,000 annually from January 1, 2025 through December 31, 2026. PSE anticipates responding to about 21,000 to 22,000 odor calls annually and repairing 1,000 to 1,200 hazardous leaks each year.

Q. Please describe the basis for the forecasted emergency repair investments in more detail.

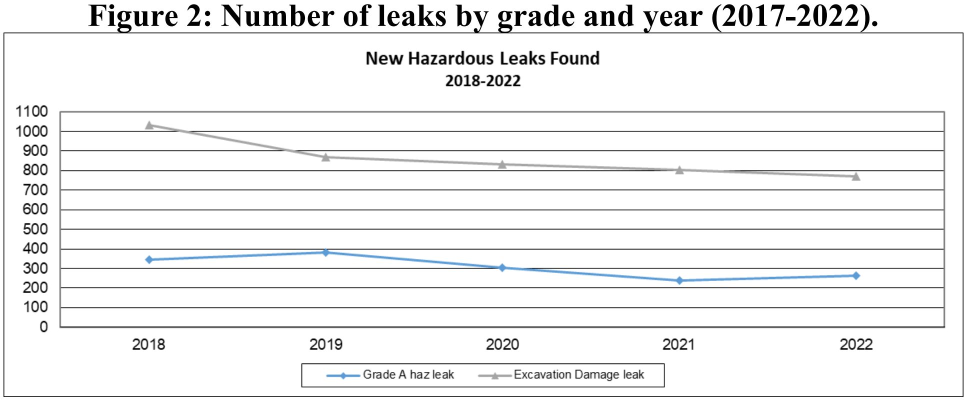
A. Forecasted funding is generally based on historical failure trends and costs adjusted by traditional escalators such as inflation, labor, and materials. Figure 1 demonstrates a relatively consistent level of unplanned electric Delivery System outages from year to year, requiring continued investment in emergency repair. However, labor and material costs have continued to increase, with service provider increased costs for unit pricing of repairs up 3.5% per year in 2023 and 2024, and growing to a 5% per year increase in 2025 and 2026, per contractual agreements.

Figure 1: Number of electric Delivery System unplanned outages by year (2019-2023).



In the case of gas emergency repair funding, while PSE has made tremendous progress in reducing the number of recorded leaks over the last 15 years, new Grade A hazardous gas leaks, as shown in Figure 2, have exhibited a slight upward trend, requiring a continued increase in investment associated with emergency response to these leaks. Excavation damage leaks are on a downward trend, attributed to increased personnel and investment in damage prevention programs.

Figure 2: Number of leaks by grade and year (2017-2022).



These emergency repair investments are not ranked against the evaluation criteria in the Investment Decision Optimization Tool ("iDOT") planning model because they are non-discretionary work that must be performed.

Q. Please describe the benefits of emergency repair investments.

A. Emergency repair investments maintain the safety of customers and the public. Because these investments are primarily reactive when an event occurs, such as an outage or leak, they are non-discretionary and the traditional idea of benefit-cost analysis to determine if the investment is warranted does not apply. However, programmatic investments discussed in sections E through P provide planned investments, optimized over time, for maintaining the Delivery System to address root causes of failure and reduce the need for emergency repair investments.

Q. Please describe the performance metrics that these investments impact.

A. These investments generally impact the following corporate performance metrics by how quickly a repair can be made and power restored:

- Failure to restore electric service within 24 hours of an outage during non-major storms.
- Failure to restore electric service within 120 hours of an outage.
- SQI #3 – SAIDI.
- SQI #4 – SAIFI.
- SQI #7 – Average gas field response time.
- SQI #11 – Average electric field response time.
- SQI #2 – Complaints to the WUTC per 1,000 customers.

D. Public Improvement

Q. Please describe PSE's public improvement investments and core objectives and priorities.

A. Public improvement investments are in response to requests by municipalities to relocate facilities as specified in jurisdictional franchise agreements. The relocations address conflicts that arise in association with jurisdictional infrastructure improvements. The core objectives of this work and investments are to respond timely to resolve conflicts with transportation improvement plans, and to minimize relocation impacts. In addition to the relocation requests from numerous jurisdictions, PSE also invests in addressing jurisdictional control zone requirements, specifically required by King County and Washington State Department of Transportation ("WSDOT"), relocating poles further away from the fog line where deemed a safety risk. Associated with operating within the public right of way, PSE invests in managing and negotiating its 180 operating franchises in 121 jurisdictions in which PSE has infrastructure in the public right of way, acquiring and maintaining mitigation land for infrastructure constructed in the habitat of protected species, such as the Mazama Pocket Gopher in Thurston County, ongoing fees and leases for land and rights that PSE infrastructure is located in including tribal lands, railroad right of way, government property, or property held for future work, and addressing and preventing transient activity on PSE property such as in areas of transmission right of way and substation properties. Similar to emergency repair investments, public improvement investments take priority over discretionary work. These investments are supported by CSA requests provided in Appendices C, D, E, and F.

Q. Please provide PSE's planned public improvement capital investments over the rate period presented in this case.

A. Table 3 provides the planned capital investments from January 1, 2025 through December 31, 2026, which are estimated based on historic trends and plans.

Table 3: Summary of public improvement capital investments by year.

Program ($ millions)	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Electric Public Improvement Capital investment	55.4	57.2
King County Clear Zone	3.5	3.6
WSDOT Control Zone Mitigation	3.6	3.5
Electric Relocations (#)	410	430
Gas Public Improvement Capital investment	27.5	28.4
Gas Relocations (#)	220	230
Real Estate & Land Planning	9.5	7.8

Additionally, there is incremental OMRC associated with the above periods totaling approximately $10 million over the two years.

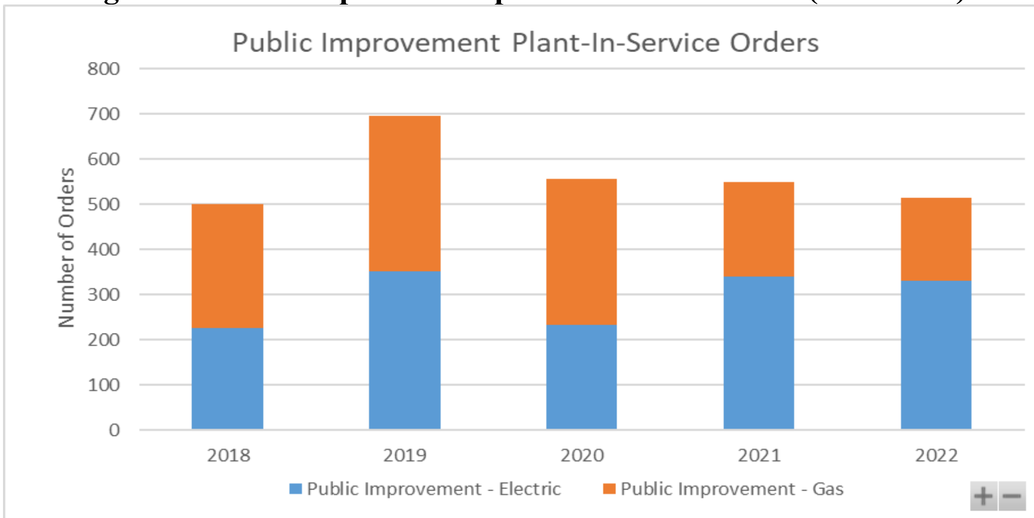
Q. Please describe the work to be completed and anticipated through the end of the rate plan.

A. PSE anticipates 575 to 760 transportation relocation projects annually including relocation for 66 to 100 fish culverts, 20 Sound Transit projects, and an anticipated increase in transportation projects that will result from the Infrastructure Investment and Jobs Act ("IIJA"). As the project scope, cost, and schedule are driven by the jurisdiction, the actual costs may vary from the forecasted investment plan. Additionally, projects can be delayed or accelerated based on the jurisdiction's annual budget or funding level.

Q. Please describe the basis for the forecasted public improvement investments in more detail.

A. Forecasted funding is generally based on the current year's public improvement investments inflated by traditional escalators such as inflation, labor, materials, and contracts, and adjusted to include known projects received from the jurisdictions. This work is not evaluated and ranked in iDOT because it is non-discretionary and required for compliance with franchise obligations. Forecasts include reimbursements from jurisdictions per franchise agreements. Figure 3 provides the public improvement project trends since 2018. Historical trends have been less useful in recent years due to the disruption of COVID-19 and subsequent economic and behavior impacts on jurisdictional decisions regarding transportation plans. Additional variability is now being introduced by funding available through the IIJA, which may lead to a greater increase in public improvement projects during the multiyear rate plan.

Figure 3: Public improvement plant in service orders (2018-2022).



While PSE is informed by local transportation improvement plans, some of them five to ten years out, factors such as the economy and national or state transportation infrastructure grants often shift project schedules which can contribute to annual variability and changes from forecasted investment levels. The annual funding level is re-forecasted each year as a result of this significant variability. As noted, public improvement investments are not ranked against the evaluation criteria in the iDOT planning model.

Q. Please describe benefits of the public improvement investments.

A. Because these investments are primarily reactive to jurisdictional projects and obligations, such as relocating a pole or gas main before or in coordination with a local transportation project, the traditional idea of benefit-cost analysis to determine if the investment is warranted does not apply. In fact, public improvement work may contribute negatively to Delivery System performance metrics such as electric reliability, SAIDI and SAIFI, if an outage must be taken to perform the required work or elements of PSE’s system must be taken out of service during the jurisdictional construction period. The reliability and automation and pipeline safety programmatic investments may factor in, when known, to jurisdictional plans and trends, for example, by proactively moving poles for clear zone requirements or moving infrastructure out of the public right of way to easements.

Q. Please describe the performance metrics that these investments impact.

A. These investments generally impact the SAIDI and SAIFI corporate performance metrics by avoiding an outage or, more negatively, by a scheduled outage and the length of time it takes to complete the work and restore power. Safety is at the forefront of all work performed by PSE, and while efforts are made to reduce the duration and frequency of outages associated with public improvement work, it is of utmost importance the work be performed safely and the system de-energized if necessary to maintain the safety of workers. With continuing growth in the region and a high-volume of public improvement projects completed every year, PSE proposes to remove impacts of scheduled planned outages from its SQI #3 – SAIDI and SQI #4 – SAIFI performance metrics given these outages are outside the influence of PSE's system reliability investments and less disruptive to customers than unplanned outages. This proposal to modify SQI #3 and SQI #4 methodology is presented in Landers, Exh. DJL-1T.

E. Electric Maintenance – Overview

Q. Please describe the key program plans included in the Electric Maintenance program.

A. The Electric Maintenance program focuses on planned maintenance or "preventative maintenance," the proactive repair and/or replacement of infrastructure that is in poor health based on inspections or diagnostics, such as replacing a pole that has begun to weaken but failure is not imminent and therefore there is time to address the concern in a planned manner. There are three key program plans that PSE is investing in over the rate plan: Substation Reliability, Pole Inspection and Remediation, and Mobile Substations.

F. Electric Maintenance – Substation Reliability

Q. Please describe the Substation Reliability maintenance program plans and core objectives and priorities.

A. PSE has 387 transmission and distribution substations that are aging and critical to maintaining reliability for PSE's customers. Many substations have assets that are over 40 years old. It is imperative to replace these assets before failure results in outages that will impact customers. The cost of an unexpected failure can be costly if there is no other way to provide power to customers. Not only is there a consequence impact to customers, but associated substation equipment may be damaged which increases the cost of managing the system. Unexpected failures of older generations of equipment can also be more costly to repair as spares may not be readily available. PSE reviews diagnostic systems and field-informed concerns to understand asset conditions and develop program plans. This is supported by CSA requests provided in Appendix G and supporting business plans which describe program background, statement of need, scope, benefits, cost estimates, alternatives, and funding risks.

Q. Please provide PSE's planned Substation Reliability maintenance capital investments and work over the rate period presented in this case.

A. Table 4 provides the planned capital investments from January 1, 2025 through December 31, 2026, which are estimated based on historic trends and programmatic plans.

Table 4: Summary of maintenance capital investments by year.

Program ($ millions)	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Substation Reliability	37.3	36.4
Projects (#)	24	31

Additionally, there is incremental OMRC associated with the above periods totaling approximately $0.5 million over the two years.

Q. Please describe the basis for the forecasted maintenance investments in more detail.

A. The Substation Reliability program has historically been funded at or below $10 million annually. In 2021, the annual budget was raised to approximately $15 million and in 2022, it was again raised to approximately $30 million. Funding is increasing to approximately $36 million in 2024 and holding steady at $36-37 million per year in 2025 and 2026. The main driver for program funding ramp-up is the large quantity of aging and obsolete substation infrastructure that PSE currently operates that presents an increasing risk of failure.

Forecasted funding is a combination of known planned projects supplemented by the historic programmatic trend of these types of investments. Please see the Substation Reliability Business Plan in Appendix G for additional program background and details.

Q. Have benefits been realized from the Substation Reliability maintenance program?

A. Future plan benefits can be based on historical benefits realized. Since the beginning of 2022, the plan resulted in avoiding approximately 135,000 customer minutes of interruption ("CMI").

Q. Please describe the benefits that the Substation Reliability maintenance program will deliver for customers through the rate plan.

A. Replacing aging and obsolete substation assets reduces outages, health and safety concerns, and environmental impacts. Table 5 provides a summary of anticipated key benefits that will be delivered by these investments.

Table 5: Summary of substation reliability maintenance investments benefits by year.

Type of benefit	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Avoided Electric Customer Minute Interruption (# millions)	0.3	0.2

G. Electric Maintenance – Pole Inspection and Remediation

Q. Please describe the Pole Inspection and Remediation maintenance program plans and core objectives and priorities.

A. The Pole Inspection and Remediation Program maintains situational awareness of the structural integrity of the overhead electric system supporting structures to optimize asset lifecycle and mitigate system risks. It is a programmatic approach to address pole health, extend pole life, and address poor condition assets before they fail and cause an outage. The core objective of the plan is to maintain that PSE's pole assets are reliable and resilient to the many external forces experienced. At the time of inspection, PSE will perform treatment that defends against wood-destroying fungi and insect damage, extending the life of a healthy pole for ten years. If poles are found to be deficient, they are remediated through reinforcement or replacement. PSE's pole program also addresses historic wishbone cross arm construction which is failure prone. This is supported by CSA requests provided in Appendix H and supporting business plans which describe program background, statement of need, scope, benefits, cost estimate, alternatives, and funding risk.

Q. Please provide PSE's planned Pole Inspection and Remediation maintenance capital investments and work over the period presented in this case.

A. Table 6 provides the planned capital investments from January 1, 2025 through December 31, 2026, which are estimated based on historic trends and programmatic plans.

Table 6: Summary of pole inspection and remediation capital maintenance investments by year.

Program ($ millions)	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Pole Inspection and Remediation	19.9	14.2
Inspections (#)	34,000	34,000
Replacements (#)	929	624

Additionally, there is incremental OMRC associated with the above periods totaling approximately $1.7 million over the two years.

Q. Please describe the basis for the forecasted maintenance investments in more detail.

A. In 2019, PSE completed a ten-year inspection and remediation cycle of all transmission poles, but had inspected only 24% of distribution poles operating on a 30-year inspection and remediation cycle. PSE reviewed this plan against industry best practices and moved to performing pole inspection of transmission and distribution infrastructure on a ten-year cycle. The program was revamped in 2019 with a budget of approximately $9.5 million annually and has been increasing funding each year through 2023 to address normal inspections along with a backlog of degraded poles. In 2023, the budget for the program was $31 million with program funding decreasing in 2025 and 2026 as the backlog of work is caught up and the normal cycle of inspection and replacements is expected. The proposed funding maintains the designated program inspection cycle for the full population of poles and avoids accumulation of backlog. The cost estimate is based on contractual unit pricing and overall average historical costs adjusted by escalators.

Q. Have benefits been realized from the Pole Inspection and Remediation maintenance program?

A. Yes. Confidence in future plan benefits can be based on historical benefits realized. In 2022, this program saved 1,430,000 CMI through replacement and reinforcement of transmission and distribution poles.

Q. Please describe the benefits that the Pole Inspection and Remediation maintenance program will deliver for customers through the rate plan.

A. The primary benefit of the maintenance investments to customers is avoided outages. Proactive maintenance and replacement also reduces rate impacts of emergency repairs. If maintenance concerns are left unaddressed, assets will eventually fail and require replacement or repair under emergency conditions, resulting in higher costs and customers being impacted by outages. Table 7 provides a summary of the benefits that will be addressed by these investments.

Table 7: Summary of pole inspection and remediation maintenance investments benefits by year.

Type of benefit	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Avoided Electric Customer Minute Interruption (# millions)	1.6	1.1

<u>H. Electric Maintenance – Mobile Substations</u>

Q. Please describe the Mobile Substations maintenance program plans and core objectives and priorities.

A. PSE operates a fleet of five mobile substations that are deployed to temporarily take the place of stationary substation equipment during outage events, such as a major equipment failure or during a project to replace existing major equipment and reduce service impacts to customers. Historically, when an extended outage was required on a piece of critical substation equipment, affected circuits would be switched to receive power from neighboring substations. While this solution is the preferred way to provide backup power, it is increasingly unavailable due to increasing load growth on PSE's system and increasing quantity of projects underway simultaneously as necessitated by growing demand for reliability and capacity improvements. As switching becomes a less viable strategy, mobile substations are increasingly needed to act as a temporary replacement for affected equipment. The increasing demand for mobile substations contrasts with the current state of PSE's existing mobile substations fleet. Three of five existing mobile substations have exceeded or are near their expected lifetime of 50 years. Out of these three units, two are rated to provide less than 25 MVA which is inadequate to supply replacement power in many of PSE's substations. A lack of readily available and healthy mobile substations can create delays to projects or emergency restoration of outages. For unplanned work, the impact of mobile substations being unavailable or out of service for repairs can result in extended outages. As the mobile substations age, they are requiring more maintenance and repairs that is limiting their use to support system work and reduce customer service reliability concerns. PSE will invest in four additional mobile substations and replace three of the existing mobile substations to reliably meet the demand for planned work and support restoration of unplanned outages. This is supported by CSA requests provided in Appendix I and supporting business plans which describe program background, statement of need, scope, benefits, cost estimate, alternatives, and funding risk.

Q. Please provide PSE's planned Mobile Substations maintenance capital investments over the rate period presented in this case.

A. Table 8 provides the planned capital investments from January 1, 2025 through December 31, 2026, for mobile substation replacement and acquisition.

Table 8: Summary of mobile substations capital maintenance investments by year.

Program ($ millions)	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Mobile Substations	0	11.1
Assets (#)	0	3

There is no incremental OMRC associated with this investment.

Q. Please describe the basis for the forecasted maintenance investments in more detail.

A. Project costs for this investment are based on recent quotations from multiple manufacturers. The focus of this investment is to replace aging mobile substations to better support programmatic work and major outage restorations.

Q. Have benefits been realized from the Mobile Substations maintenance program?

A. The current fleet of mobile substations are typically in use for a minimum of five days at a time per project or restoration event. On average, the current fleet of mobile substations is in use for 45 days per year, typically maintaining service to around 4,000 customers per deployment. This investment will help facilitate the completion of increasing project quantities requiring switching of substation circuits as the grid is modernized to support growing load and integration of clean energy distributed energy resources. Additionally, this investment will increase PSE's preparedness for restoration of power during unplanned substation outage events.

Q. Please describe the benefits that the Mobile Substations maintenance program will deliver for customers through the rate plan.

A. The primary benefit of Mobile Substations is to enable restoration of service to a large population of customers in the event of a major outage due to a storm or major equipment failure that takes an existing substation off-line. Mobile Substations are also used to provide backup power during major substation construction projects that require a planned outage.

I. Gas Maintenance – Overview

Q. Please describe the key program plans included in the Gas Maintenance program.

A. The Gas Maintenance program focuses on identifying pipeline safety risk and integrity management concerns in both the distribution and transmission systems and meeting increasing regulatory requirements related to pipeline safety. The program includes planned maintenance and proactive repair and/or replacement of higher risk infrastructure, an example being replacement of pipe that is prone to leakage, but risk of imminent failure is low, and time exists to address the concern in a planned manner. There are seven key programs PSE is investing in over the rate plan. Under the Pipeline Replacement Plan ("PRP") are the following four programs: Older Vintage PE Pipe Mitigation Program, Buried Meter Set Assembly ("MSA") Remediation Program, Sewer Cross Bore Program, and No Record Facility Remediation Program. The three additional programs are Distribution Integrity Management Program & Accelerated Actions, Enhanced Methane Emissions Reduction, and Transmission Integrity Management Program.

J. Gas Maintenance – PRP Older Vintage PE Pipe Mitigation Program

Q. Please describe the PRP Older Vintage PE Pipe Mitigation Program plans and core objectives and priorities.

A. An increased risk of premature, brittle-like cracking of larger diameter (1-1/4" and larger) Aldyl High-Density PE pipe manufactured by DuPont has been identified in the distribution system. DuPont pipe was installed in the 1970s and early 1980s and there was an initial estimate that 400 miles was still in service as of 2013. After further detailed review, the estimate increased to nearly 435 miles in service at the beginning of 2013, prior to any pipe replacement completed under the filed PRP. The risk associated with DuPont pipe is an industry problem and is one that peer utilities in Washington are also actively addressing. The brittle-like cracking occurs as slow crack growth at locations where there is a stress concentration on the pipe. Based on PSE's experience, the brittle-like cracking is primarily due to rock impingement but also occurs where the pipe has previously been squeezed or where other stress concentrations have been introduced due to inconsistent joining practices. The failure is referred to as brittle-like cracking because it occurs without any localized plastic deformation. While the failure occurs without plastic deformation, the pipe is not brittle. Even when a failure occurs due to slow crack growth, the PE pipe remains resistant to crack propagation preventing it from becoming a larger crack. A study by the Gas Technology Institute performed at PSE's request provided additional insight into how installation and operating practices, environmental conditions, and operating pressures impact life expectancy of the pipe. A program was developed and implemented in 2010 to prioritize larger diameter older vintage PE Pipe for replacement, specifically DuPont Aldyl "HD" plastic pipe based on the likelihood and consequence of failure. The program was incorporated into integrity management programs and evaluated the risk of brittle-like cracking based on installation and operating practices and environmental conditions. These segments of larger diameter DuPont Aldyl "HD" plastic pipe have an elevated risk of failure as validated by Distribution Integrity Management Program ("DIMP") system performance data. At the end of 2022, 210.5 miles of DuPont have been retired. The core objectives of this work and investments are to maintain continuing integrity of the existing gas system by addressing predicted safety concerns in the most cost-effective manner through planned programmatic investments. The program is supported by CSA requests provided in Appendix J and supporting business plans which describe program background, statement of need, scope, benefits, cost estimate, alternatives, and funding risk. Additionally, PSE provides Appendix K which is a copy of PSE's latest PRP.

Q. Please provide PSE's Older Vintage PE Pipe Mitigation Program planned maintenance capital investments and work over the rate period presented in this case.

A. Table 9 provides the planned capital investments from January 1, 2025 through December 31, 2026, which are estimated based on historic trends and programmatic plans.

Table 9: Summary of PRP Older Vintage PE Mitigation Program capital investments by year.

Program ($ millions)	**Rate Plan Year 1 2025**	**Rate Plan Year 2 2026**
PRP Older Vintage PE Mitigation Program	57.4	58.6
Assets (miles)	19	24

There is no incremental O&M associated with the above periods.

Q. Please describe the basis for the forecasted maintenance investments in more detail.

A. Since the beginning of the plan, PSE has averaged 20 miles a year of DuPont pipe replacement, ranging from about ten miles to 40 miles a year depending on specific project conditions and, in part, on managing the impact of the PRP on ratepayers.[1] PSE's plan continues to invest at this programmatic pace, targeting from 19 to 24 miles per year, based on capacity of third-party resources, customer intensive coordination, permitting processes, and street restoration requirements.

[1] RCW 80.28.420(2) requires: "A gas company seeking an interim recovery between rate cases may submit to the commission, as part of . . . a commission–approved interim rate treatment mechanism regarding the replacement of pipeline facilities, a description . . . As part of the proposal, the gas company must address the expected impact to ratepayers . . . ."

The programmatic cost to replace the entire population of DuPont per the Older Vintage PE Pipe Mitigation Business Plan is approximately $1,048 million. The cost is estimated based on current contractual unit pricing and overall average historical costs adjusted by traditional escalators such as inflation, labor, materials, and contract.

Q. Have benefits been realized from the PRP Older Vintage PE Mitigation Program?

A. Yes. Confidence in future plan benefits is based on historical benefits realized. From the beginning of 2018 through the end of 2022, the plan has reduced the inherent integrity management risk[2] by 24.8%.

Q. Please describe the benefits that the PRP Older Vintage PE Pipe Mitigation Program will deliver for customers through the rate plan.

A. Primary benefits of the plan are increased safety due to replacing pipe that is prone to failure and avoided emergency repair costs from avoided leaks. If maintenance concerns are left unaddressed, older vintage PE pipe assets will eventually fail and, depending on location of failure, leaking gas could potentially migrate into building structure(s) creating safety risks and requiring replacement or repair under emergency conditions, resulting in higher costs and customers being impacted by outages. Table 10 provides a summary of avoided methane

[2] The Distribution Integrity Management Plan program measures risk across many factors for a given threat which is quantified numerically for risk comparison with other threats. Reducing this risk number for a given program means the threat is decreasing, but is it a relative analysis.

emissions, avoided emergency repair costs, and risk reduction that will be accomplished through these investments.

Table 10: Summary of PRP Older Vintage PE Pipe Mitigation Program investments benefits by year.

Type of benefit	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Avoided Emissions (MTCO2e)	43	54
Avoided emergency leak repair cost ($)	$37,000	$47,000
Avoided Integrity Risk (%)	8.5%	10.6%

K. Gas Maintenance – PRP Buried MSA Mitigation Program

Q. Please describe the PRP Buried MSA Mitigation Program plans and core objectives and priorities.

A. An increased risk on the meter or MSA piping has been identified where pipe, fittings, or equipment intended for above ground exposure, is unintentionally buried. The condition occurs when a homeowner/building owner makes changes to the ground elevation in the area of the meter and may result in hazardous leaks due to corrosion occurring at or near a building wall. Buried MSAs are identified from routine leak surveys and subsequent field inspections. With the meter set at the building wall, the consequence of a leak or failure poses a greater risk as gas can travel into the home or business. The core objectives of this work and investments are to maintain customer safety by addressing predicted safety concerns in the most cost-effective manner through planned programmatic investments. This is supported by CSA requests provided in Appendix L and supporting business plans which describe program background, statement of need, scope, benefits, cost estimate, alternatives, and funding risk. Additionally, PSE provides Appendix K which is a copy of PSE's latest PRP.

Q. Please provide PSE's PRP Buried MSA Mitigation Program planned maintenance capital investments and work over the rate period presented in this case.

A. Table 11 provides the planned capital investments from January 1, 2025 through December 31, 2026, which are estimated based on historic trends and programmatic plans.

Table 11: Summary of PRP Buried MSA Mitigation Program capital investments by year.

Program ($ millions)	Rate Plan Year 1 2025	Rate Plan Year 2 2026
PRP Buried MSA Mitigation Program	6.5	7.0
Assets (#)	7,000	7,000

Additionally, there is incremental O&M associated with the above periods totaling approximately $2.0 million over the two years.

Q. Please describe the basis for the forecasted maintenance investments in more detail.

A. PSE had identified an initial population of 40,000 buried meters in the June 2019 PRP, with the intent of replacement of this population by 2025. Since the beginning of the plan in 2014, PSE has averaged remediation of about 3,000 buried meters a year, ranging from 500 to 7,000 per year. Using historical project execution success from remediating 36,638 buried meters as of year-end 2022, the programmatic cost to complete 40,000 per this plan is approximately $35 million.

In 2026, a new population will be assessed and a master plan for remediation will be developed as needed. The cost estimate is based on contractual unit pricing and overall average historical costs adjusted for additional costs for those meter set risers in hard surfaces that require a saw cut to remediate and by traditional escalators.

Q. Have benefits been realized from the PRP Buried MSA Mitigation Program?

A. Yes. Confidence in future plan benefits is based on historical benefits realized. Due to a significant increase in new reports of buried MSAs, the inherent risk has increased by 14.8% from the beginning of 2018 through the end of 2022. With no investment in this plan, the risk would have increased by 60.0%.

Q. Please describe the benefits that the PRP Buried MSA Mitigation Program will deliver for customers through the rate plan.

A. The primary benefit of the PRP Buried MSA Mitigation Program to customers is improved safety by reducing corrosion and risk of leaks at the building wall from unintentionally buried MSA components. If these maintenance concerns are left unaddressed, assets will eventually fail and potentially produce leaks that migrate into building structure(s) creating safety risks and requiring replacement or repair under emergency conditions, resulting in higher costs and customers being impacted by outages. Table 12 provides a summary of the avoided methane emissions, avoided emergency repair costs, and risk reduction that will be achieved by these investments.

Table 12: Summary of PRP Buried MSA Mitigation Program investments benefits by year.

Type of benefit	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Avoided Emissions (MTCO2e)	0.4	0.4
Avoided emergency leak repair cost ($)	$4,000	$4,000
Avoided Integrity Risk (%)	1.8%	1.8%

L. Gas Maintenance – PRP Sewer Cross Bore Program

Q. Please describe the Pipeline Replacement Plan Sewer Cross Bore program plans and core objectives and priorities.

A. The PRP Sewer Cross Bore Program mitigates integrity risks from gas pipelines that were inadvertently installed through unmarked sewer pipe. The program utilizes sewer inspections to identify and remediate cross bores and a public awareness plan to publicize the program to prevent inadvertent damage to cross bored gas lines during actions taken to clear blocked sewer lines. The primary strategy includes increased public awareness and outreach, inspection of legacy facilities, stopping new cross bores from being undetected and left in place after new construction, response training, and pipe replacement. By 2029, the plan is to inspect 60,000 legacy segments identified as higher risk for sewer cross bore and remediate any findings. The target population is 15% of the estimated total population of possible sewer cross bores. Upon completion, additional legacy areas that have higher risk for sewer cross bores will be analyzed and a new target population identified as needed. Approximately 8,000 sewer lines are also inspected each year after construction of new infrastructure to confirm no new sewer cross bores have occurred. Finally, through public outreach and a program to respond to blocked sewer lines, customers and plumbers can call when a blocked sewer is suspected and PSE will inspect their sewer line in advance of the line being cleared. There are approximately 300 blocked sewer calls received by PSE per year with approximately 22 percent resulting in identification of a sewer cross bore. The core objective of this work is to maintain customer safety by addressing predicted safety concerns in the most cost-effective manner through planned programmatic investments. This is supported by CSA requests provided in Appendix M and supporting business plans which describe program background, statement of need, scope, benefits, cost estimate, alternatives, and funding risk. Additionally, PSE provides Appendix K which is a copy of PSE's latest PRP.

Q. Please provide PSE's PRP Sewer Cross Bore planned maintenance capital investments and work over the rate period presented in this case.

A. Table 13 provides the planned capital investments from January 1, 2025 through December 31, 2026, which are estimated based on historic trends and programmatic plans.

Table 13: Summary of PRP Sewer Cross Bore Program capital investments by year.

Program ($ millions)	Rate Plan Year 1 2025	Rate Plan Year 2 2026
PRP Sewer Cross Bore Program	0.5	0.5
Assets (#)	7,300	7,300

Additionally, there is incremental O&M associated with the above periods totaling approximately $9.4 million over the two years.

Q. Please describe the basis for the forecasted maintenance investments in more detail.

A. PSE estimates it has nearly 400,000 total sewer segments to investigate, with the goal of evaluating 60,000 by 2029. Beginning in 2020, PSE planned to invest at an accelerated pace of about 7,300 sewer segment inspections a year due to the continued significant risk discussed and approved in the 2023 PRP. Using historical project execution success from completing over 35,060 legacy inspections to date, the programmatic cost to complete 60,000 legacy segments per this plan is approximately $41 million, the majority of which is O&M expense. The cost estimate is based on contractual unit pricing and overall average historical costs per inspection adjusted for additional costs for jurisdictions that have multiple sewer segments per parcel.

Q. Have benefits been realized from the PRP Sewer Cross Bore Program?

A. Yes. Confidence in future plan benefits is based on historical benefits realized. The plan has effectively eliminated 1,004 sewer cross bores from the start of the program in 2013 through the end of 2022. The plan has also reduced the inherent integrity management risk by 22.0% from the beginning of 2018 through the end of 2022.

Q. Please describe the benefits that the PRP Sewer Cross Bore Program will deliver for customers through the rate plan.

A. The benefit of less sewer cross bores is increased customer safety. If sewer cross bores are left unaddressed, the gas pipe could be damaged during sewer cleaning and provide a path for the leak into the home. Table 14 provides a summary of the avoided methane emissions, avoided emergency repair costs, and risk reduction that will be addressed by these investments.

Table 14: Summary of PRP Sewer Cross Bore Program investments benefits by year.

Type of benefit	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Avoided Emissions (MTCO2e)	10	10
Avoided emergency leak repair cost ($)	$2,000	$2,000
Avoided Integrity Risk (%)	10.1%	10.1%

M. Gas Maintenance – PRP No Record Facility Remediation Program

Q. Please describe the No Record Facility Remediation Program plans and core objectives and priorities.

A. The No Record Facility Remediation Program mitigates integrity risks from service lines that cannot be found in the field and no facility records indicate they have been retired. No Record Facilities ("NRF") are service lines that typically had the meter removed without a D4 record documenting it. Over time, the remaining idle riser was then skipped during leak surveys and patrols because a meter could not be found. Subsequently, the mapping system was often also updated with "NR" to indicate a no record cut and cap, and a cap symbol was placed on the service showing the facility retired without an official retirement record. Closer examination of the population has shown that NRFs are often buried or hidden due to non-use and may not actually be retired as the no record cut and cap suggests. The program strategy is to perform field investigation and excavate at the tie-in location to perform a cut and cap of the service line, or to confirm an existing cut and cap. The core objectives of this work and investments are to maintain customer safety by addressing predicted safety concerns in the most cost-effective manner through planned programmatic investments. This is supported by the No Record Facilities Business Plan provided in Appendix N that describe program background, statement of need, scope, benefits, cost estimate, alternatives, and funding risk. Additionally, as noted above, Appendix K is a copy of PSE's latest PRP.

Q. Please provide PSE's planned PRP No Record Facility Remediation Program capital investments and work over the rate period presented in this case.

A. Table 15 provides the planned capital investments from January 1, 2025 through December 31, 2026. which are estimated based on programmatic plans. The No Record Facility Remediation Program, while part of the PRP, is included in the DIMP discussed in the next section of this exhibit. Annual capital investments are provided in Table 15 below to provide full program detail, but as noted in the table, these investments are not additive to the investments listed for DIMP in Section N of this exhibit.

Table 15: Summary of PRP No Record Facility Remediation Program capital investments by year.

Program ($ millions)	**Rate Plan Year 1 2025**	**Rate Plan Year 2 2026**
PRP No Record Facility Remediation Program	0.5*	1.0*
Assets (#)	400	800

*PRP No Record Facility capital investments are included in the DIMP program. The above investments are not additive to investments presented for DIMP in Table 17 of this exhibit.

Additionally, there is incremental O&M associated with the above periods totaling approximately $4.5 million over the two years.

Q. Please describe the basis for the forecasted PRP No Record Facility Remediation Program investments in more detail.

A. Using historical project execution success from similar work performed in the Idle Riser Program, the programmatic cost to complete 3,000 No Record Facilities per this plan is approximately $15 million, at a rate of approximately 75% O&M expense based on results of the program pilots. The cost estimate is based on contractual unit pricing and overall average historical costs for deactivating for cut and cap of the service or performing a verification of an existing cut and cap, and performing field and records review.

Q. Have benefits been realized from the PRP No Record Facility Remediation Program?

A. Only pilot investigations have been performed thus far to inform program design. The program will begin in 2024 and continue into the period covered by this multiyear rate plan.

Q. Please describe the benefits that the PRP No Record Facility Remediation Program will deliver for customers through the rate plan.

A. The primary benefit of the PRP No Record Facility Remediation Program is to increase safety by remediating services that may have been improperly deactivated and present a higher risk from leaks due to location in the vicinity of the previously served building wall. Table 16 provides a summary of the benefits that will be addressed by these investments.

Table 16: Summary of PRP No Record Facility Remediation Program investments benefits by year.

Type of benefit	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Avoided Integrity Risk (%)	14.4%	14.4%

N. Gas Maintenance – Distribution Integrity Management Program & Accelerated Actions

Q. Please describe the Integrity Management & Accelerated Actions program plans and core objectives and priorities.

A. PHMSA 192 Subpart P[3] requires gas operators to have a distribution integrity plan, follow it, identify pipeline risk, and mitigate risks as needed. PSE is audited regularly regarding compliance with required law, including its adherence to the integrity management requirements. PSE's DIMP identifies the risk to the system and develops mitigation plans based on risk through additional or accelerated maintenance activities. There are additional and accelerated plans in addition to the ones captured in the PRP which focus on elevated safety risks. As required by code, distribution risks identified from the plan are reported to the WUTC through the Continuing Surveillance Report annually. The program also addresses emerging cathodic protection repairs, found through inspection, that are required within 90 days. The core objectives of this work and investments are to maintain longevity of the existing gas system by addressing predicted health and safety

[3] 49 C.F.R. § 192(p).

concerns in the most cost-effective manner through planned programmatic investments. This is supported by CSA requests provided in Appendix M and supporting business plans which describe program background, statement of need, scope, benefits, cost estimate, alternatives, and funding risk.

Q. Please provide PSE's Distribution Integrity Management & Accelerated Actions Program planned maintenance capital investments and work over the rate period presented in this case.

A. Table 17 provides the planned capital investments from January 1, 2025 through December 31, 2026, which are estimated based on historic trends and programmatic plans.

Table 17: Summary of Distribution Integrity Management Program & Accelerated Actions capital investments by year.

Program ($ millions)	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Distribution Integrity Management Program & Accelerated Actions	31.8*	33.9*
CAP units (#)	790	790

*Capital investments for No Record Facilities, discussed in Section M of this exhibit, are included in this DIMP total.

Additionally, there is incremental O&M associated with the above periods totaling approximately $9.5 million over the two years.

Q. Please describe the basis for the forecasted maintenance investments in more detail.

A. PSE's DIMP requires PSE to identify and reduce pipeline safety and integrity risks. PSE assigns each additional and accelerated action into low, moderate-high, and top priority risks. Since the beginning of the plan, PSE has remediated an average of 500 projects. The rate plan focuses on newer programs with more individual units that will gradually increase over the plan period. Some DIMP programs are absorbed into normal operations practices or within the implementation of new materials to address specific issues. PSE's plan continues to invest at this programmatic pace, targeting a reduction of about 40 risk points annually to a manageable steady risk tolerance of 150 risk points across PSE's entire pipeline system by 2030. PSE estimates the investment to reach that risk level (150 risk points) is approximately $185 million from 2022 to 2030 in addition to on-going investments for programs already at steady state and to initiate programs in the early stages of development. The DIMP Additional and Accelerated Actions address thousands of individual projects annually across various programs, taking into account the capacity of third-party resources, customer intensive coordination, and permitting processes. The cost estimate is based on contractual unit pricing and overall average historical costs per project adjusted for traditional escalators.

Q. Have benefits been realized from the Distribution Integrity Management Program & Accelerated Actions program?

A. Yes. Confidence in future plan benefits can be based on historical benefits realized. From the beginning of 2018 through the end of 2022, the plan has effectively reduced the inherent integrity management risk by 11.1%.

Q. Please describe the benefits that the Distribution Integrity Management Program & Accelerated Actions program will deliver for customers through the rate plan.

A. The rimary benefit of the Distribution Integrity Management Program & Accelerated Actions is safety and risk mitigation. Table 18 provides the benefits of risk reduction, avoided emergency repair, and methane reduction in carbon dioxide equivalent over the multiyear rate plan period.

Table 18: Summary of Distribution Integrity Management Program & Accelerated Actions Investments Benefits by year.

Type of benefit	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Avoided Emissions (MTCO2e)	594	706
Avoided emergency leak repair cost ($)	$546,000	$546,000
Avoided Integrity Risk (%)	1.6%	1.5%

O. Gas Maintenance – Enhanced Methane Emissions Reduction Program

Q. Please describe the Enhanced Methane Emissions Reduction Program plans and core objectives and priorities.

A. Methane emissions are 84 times more potent as a greenhouse gas than carbon dioxide and a focus of the Pipeline Modernization Plan. Numerous regulations are focused on limiting methane emissions including the PHMSA 2020 Pipes Act, PHMSA's NPRM on Leak Detection and Repair, and the US Methane Emissions Reduction Action Plan.

Unplanned methane emission releases occur most often as a result of damage by third party dig-ins, leaks from pipeline failures, and planned methane releases during construction activities. PSE evaluated 32 methane emission reduction tactics in 2021. Currently eight tactics have been implemented including several that were highlighted in the 2021 PRP.

The intentional or unintentional release of methane is now considered an environmental safety hazard. The plan addresses this hazard by implementing or expanding use of advanced leak detection, recompression technology, fixing nonhazardous leaks as they are found, fixing nonhazardous above ground meter leaks, and other operational improvements.

The tactics described below will be reviewed from a cost benefit standpoint for implementation each year.

- **Utilizing Advanced Leak Detection Technology.** Advanced leak detection instruments help find very small leaks and can also be used more frequently since they are mounted on a vehicle as compared to a walking leak survey. The goal of utilizing this technology is to survey the natural gas pipelines for leaks more easily so they can be surveyed more often. Shortening the duration between leak surveys means leaks can be found faster which will reduce the amount of methane emitted to the atmosphere.

- **Utilizing Recompression Technology.** The use of recompression technology is being incorporated into future replacement and retirement projects. The plan is to implement this technology for 30% of the projects and measure the costs and benefits of expanding it to more projects. The recompression technology can move gas isolated in the pipe to be deactivated to an active gas main without releasing any gas to atmosphere. Since this is a newer technology, the best use of this equipment is still being evaluated.

- **Leak Repair Methodology – Repairing Leaks upon Discovery.** The plan focuses on reducing methane emissions through accelerating repair of active non-hazardous (Grade "B" and Grade "C") below ground leaks. These leaks are not a public safety concern but can be an environmental safety concern due to the release of methane, depending on the duration of the leak. Since 2016, the backlog of leaks has been eliminated and each new leak is currently scheduled for repair as they are found. The goal is to repair new leaks on average within four months of discovery or faster.

- **Repairing Nonhazardous Above Ground Meter Leaks.** The repair of active non-hazardous above ground meter set releases of gas was implemented in 2023. The releases are typically only detectable by sensitive leak detection instruments and occur at threaded joints on meter sets. However, some of the larger releases can contribute to methane emissions over time. The smaller releases are repaired by using a new repair tape that seals up around the threads and requires less disruption to the customer than rebuilding a whole meter set. Changes in Federal Code may occur in the near future that will require the repair of these types of releases or will provide a better interpretation about which releases at meter sets require repair. The current strategy will help prepare for meeting any future regulatory requirements.

- **Other Operational Improvements.** Methane emissions estimates have been improved by calculating the emissions from leaks and other sources in operations. RCW 81.88.160 passed in 2019, requires gas operators to calculate the metric tons of methane released from leaks in CO2 equivalent, which is a different method than EPA's estimation of emissions. Calculating the emissions of each leak provides a more accurate representation of the amount of emissions from the system. The EPA estimate of a company's emissions is based on national average leakage by material type. By calculating the actual leakage emissions, approximately 13,000 metric tons of CO2 equivalent are released as a result of leaks annually, which is 75% lower than the EPA estimate using national averages by material type.

PSE is focused on reducing methane emissions and has made great progress reducing the number of leaks within the system. The implementation of new technology to survey more frequently will help find leaks faster. Fixing leaks upon discovery will also provide better understanding of what is failing in the system and coordinating replacement programs for those facilities that are more leak prone. Incorporating recompression technology will result in less gas released to the atmosphere. This action helps to keep every molecule in the pipelines.

This is supported by CSA requests provided in Appendix O and supporting business plans which describe program background, statement of need, scope, benefits, cost estimate, alternatives, and funding risk.

Q. Please provide PSE's Enhanced Methane Emissions Reduction Program planned maintenance capital investments and work over the rate period presented in this case.

A. Table 19 provides the planned capital investments from January 1, 2025 through December 31, 2026, which are estimated based on programmatic plans.

Table 19: Summary of Enhanced Methane Emissions Reduction investments by year.

Program ($ millions)	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Enhanced Methane Emissions Reduction	4.7	4.7
Opportunities pursued	2,257	2,257

Additionally, there is incremental O&M associated with the above periods totaling approximately $6 million over the two years.

Q. Please describe the basis for the forecasted maintenance investments in more detail.

A. The costs for methane emissions reduction were developed from estimating the number of nonhazardous leak repairs being completed annually that address emissions from nonhazardous leaks occurring in the natural gas distribution system. It is estimated 225 leaks will be addressed per year with a majority of the planned capital and O&M projected costs. Nonhazardous leak repairs are included in the methane emissions reduction plans with an anticipated 2,000 above ground leak repairs at meter sets with an estimated cost of $200,000 per year. To reduce the amount of emissions that occur during pipeline replacement, PSE plans to use recompression technology on projects that are decommissioning pipelines to transfer natural gas trapped in the retired pipe into nearby active pipelines. PSE plans to perform 30 recompression projects each year. Advanced leak detection is estimated at about $1 million of O&M to operate the new equipment to find leaks faster. Cost estimates for implementing new technology will continue to evolve as use of the new equipment continues at an increased frequency to reduce methane emissions.

Q. Have benefits been realized from the Enhanced Methane Emissions Reduction Program?

A. Yes, PSE has realized benefits from the actions taken by the Enhanced Methane Emissions Reduction program. By fixing leaks as they are found and eliminating the backlog of monitored leaks, nonhazardous leaks in the system have been reduced by 99%. This results in 6,343 Metric Tons CO_2 equivalent emissions savings annually.

Q. Please describe the benefits that the Enhanced Methane Emissions Reduction Program will deliver for customers through the rate plan.

A. The primary benefit of the maintenance investments is avoided methane emissions. If maintenance concerns are left unaddressed, PSE risks contributing directly to the environmental impacts through pre-consumer release of greenhouse gas emissions. Table 20 provides a summary of the avoided methane emissions that will be addressed by these investments.

Table 20: Summary of Enhanced Methane Emissions Reduction investments benefits by year.

Type of benefit	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Avoided methane emissions (metric ton CO2E)	1,736	1,736

P. Gas Maintenance – Transmission Integrity Management Program

Q. Please describe the Transmission Integrity Management Program plans and core objectives and priorities.

A. PHMSA 192 Subpart O requires gas operators to have a transmission integrity plan, follow it, identify pipeline risk, and mitigate risks as needed. PSE is audited regularly regarding compliance with required law, including its adherence to the integrity management requirements. PSE's Transmission Integrity Management Program ("TIMP") plan identifies the risk to the system and develops mitigation plans based on risk through regular assessment activities and preventative and mitigative measures. As required by code, transmission risks identified from the plan are reported to the WUTC through the TIMP Annual Report.

Recent changes to the transmission code (known as the MEGA Rule[4]) brought forth an enhanced record requirement for transmission lines which requires gas operators to evaluate whether it is prudent to replace, retire, or continue to maintain existing transmission lines. The program strategy involves performing periodic integrity assessments on 4.7 miles of transmission lines and five stations within covered segments, and performing Maximum Allowable Operating Pressure ("MAOP") reconfirmation for 11.8 miles of transmission pipeline and 15 stations that do not currently have traceable, verifiable, and complete records. Integrity assessments consist of electric surveys, in-line inspection, and in-situ

[4] RIN 2137-AF39 Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments.

direct examination. MAOP reconfirmation options consist of materials verification direct examinations, pressure testing, pressure reduction, and replacement.

Q. Please provide PSE's planned TIMP capital investments and work over the two rate periods presented in this case.

A. Table 21 provides the planned capital investments from January 1, 2025 through December 31, 2026, which are estimated based on historic trends and programmatic plans.

Table 21: Summary of Transmission Integrity Management Program capital investments by year.

Program ($ millions)	**Rate Plan Year 1 2025**	**Rate Plan Year 2 2026**
Transmission Integrity Management Program (CAP)	0.8	0.8
Miles of Integrity Assessment	1.0	1.2
Integrity Assessment Direct Examinations	0	3
Station Integrity Assessments	1	0
Miles of MAOP Reconfirmation Performed	0	3.7
Station MAOP Reconfirmation Performed	1	1

Additionally, there is incremental O&M associated with the above periods totaling approximately $4.3 million over the two years.

Q. Please describe the basis for the forecasted maintenance investments in more detail.

A. The investment forecasts have been developed using historical project execution costs for integrity assessments and integrity digs along with project-specific estimates developed at a high level for the MAOP reconfirmation projects. These estimates will continue to be refined once MAOP reconfirmation options have been selected.

Q. Have benefits been realized from the TIMP?

A. Yes, from the beginning of 2018 through the end of 2022, 3.6 miles of transmission pipe in covered segments have been been inspected by integrity assessment. MAOP reconfirmation projects will begin in 2024.

Q. Please describe the benefits that the TIMP will deliver for customers through the rate plan.

A. The primary customer benefit of the TIMP is safety and service reliability achieved by adhering to compliance obligations to perform integrity assessments for 4.8 miles of transmission main and five transmission stations periodically every seven years. The other benefit is enhanced confidence in safety of the Delivery System achieved through delivering on the MAOP reconfirmation obligation for 5.9 miles (50%) by 2028 and the total 11.8 miles and 15 stations (100%) by 2035. Table 22 provides a summary of the benefits that will be addressed by these investments.

Table 22: Summary of Transmission Integrity Management Program investments benefits by year.

Type of benefit	Rate Plan Year 1 2025	Rate Plan Year 2 2026
Miles of Integrity Assessment	1.0	1.2
Station Integrity Assessments	1	0
Miles of MAOP Reconfirmation Performed	0	3.7
Station MAOP Reconfirmation Performed	1	1

II. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.