STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

North Shore Gas Company Proposed general increase in rates and revisions to service classifications, riders and terms and conditions of service	)	Docket No. 26-0066
The Peoples Gas Light and Coke Company Proposed general increase in rates and revisions to service classifications, riders and terms and conditions of service	)	Docket No. 26-0065 (cons.)

Surrebuttal Testimony of

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On Behalf of
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I. INTRODUCTION AND BACKGROUND

A. Witness Identification

Q. Please state your name and business address.

A. We are Polly M. Eldringhoff and Jerry Dickson. We work for WEC Energy Group, the corporate parent of The Peoples Gas Light and Coke Company ("Peoples Gas," "PGL," or the "Company"). Our business address is 200 East Randolph Street, Chicago, Illinois 60601. We are sponsoring this surrebuttal testimony as a panel.

Q. Are you the same Polly M. Eldringhoff and Jerry Dickson who submitted direct and rebuttal testimony to the Illinois Commerce Commission ("Commission" or "ICC") on behalf of The Peoples Gas Light and Coke Company ("Peoples Gas" or "PGL") and North Shore Gas Company ("North Shore" or "NSG") (together, the "Companies") in this consolidated proceeding?

A. Yes. We submitted direct testimony, (NSG-PGL Exhibit ("Ex.") 3.0 REV), supplemental direct testimony (NSG-PGL Ex. 3.0 REV SUPP02), and rebuttal testimony (NSG-PGL Ex. 17.0). Our respective backgrounds, professional qualifications, and duties have not changed since that time.

B. Purposes of Surrebuttal Testimony

Q. What are the purposes of your surrebuttal testimony in this proceeding?

A. Our surrebuttal testimony serves three purposes.

First, it responds to the Pipe Retirement Program ("PRP")-related positions advanced by the Illinois Attorney General ("AG"), Commission Staff ("Staff"), Illinois

State Public Interest Research Group, Inc. ("PIRG"), City of Chicago ("City"), Citizens Utility Board ("CUB"), and the Environmental Defense Fund ("EDF"). In doing so, we identify areas of agreement among the parties, and we highlight positions that have been newly raised or materially altered since Staff and intervenors filed direct testimony.

Second, this testimony presents a material new development that occurred after Staff and intervenors filed rebuttal testimony: The Company updated its PRP forecast for work and associated costs during 2026 and 2027. Details regarding the forecast update are captured in Section III of this testimony. The forecast update was reviewed and approved by the PRP Executive Steering Committee ("ESC") on July 13, 2026. The forecast update includes actuals through the month of June and incorporates the most recent assumptions regarding projected resource availability. Surrebuttal represents the first procedural opportunity to present this information. The Commission should consider these updated forecasts because they bear directly on the AG Gas Technical Panel's ("AG Panel's") recommended PRP disallowances, which were calculated using a prior forecasted investment level and retirement plan that the Company has subsequently updated.

Third, this testimony responds to the cost and contingency related disallowance recommendations advanced by the AG Panel in AG Ex. 4.00, as well as other PRP-related recommendations and observations from Staff and intervenor rebuttal testimony. Specifically, we:

(1) We respond to the AG Panel regarding the costs of 2026 PRP projects, including the Panel's proposed $97.2 million cost disallowance, its proposed disallowance of $71.06 million in program-level contingency, and its concerns regarding the

feasibility of meeting the Commission's retirement directive deadline of January 1, 2035;

(2) We respond to Staff witness Brett Seagle regarding PRP project documentation, the status of the former 2027 "placeholder" projects, his recommendation that contingency amounts exceeding 10% be justified on a project-specific basis, and his request that Peoples Gas provide additional the calculations supporting allocated contingency amounts;

(3) We respond to PIRG witnesses regarding repair and rehabilitation technologies and cured-in-place lining ("CIPL") including by illustrating, through recent project examples, how the Company evaluates whether CIPL is an appropriate alternative in a given situation, the JANA probabilistic risk model and cost-effectiveness, non-pipeline alternatives ("NPAs") and hydraulic feasibility, and ratepayer impacts; and

(4) We respond to City witness Gregory Lander regarding NPAs and PRP reporting, to CUB witness Juan-Pablo Velez regarding targeted electrification, and to EDF witness Joseph von Fischer regarding methane emissions, leak detection, including the use of Advanced Mobile Leak Detection ("AMLD") technologies, and environmental justice.

C. Summary of Conclusions

Q. Please summarize the conclusions you reach in your surrebuttal testimony.

A. In brief, the conclusions of our surrebuttal testimony are as follows:

(1) The revision to the 2026 CI/DI retirement target from approximately 21 miles to approximately 14 miles and the corresponding adjustment in the 2026 investment level from approximately $210 million to approximately $120 million, as well as the Company's updated 2027 CI/DI retirement target of approximately 47 miles and associated 2027 investment level of approximately $349 million (with $320 million in service)—revised from the Company's original 2027 forecast of approximately $360 million—necessarily relied on actual field-performance data from the initial months of execution and therefore was not available earlier in the proceeding. These revisions reflect prudent utility planning consistent with industry practice. As actual field-performance data and other project information became available, Peoples Gas refined the scope of work that could reasonably be executed and adjusted the associated investment levels accordingly, as discussed in Section III below.

The AG Panel's recommendation should be rejected. The Panel applies a generic program-level benchmark that divides total planned investment by aggregate retirement mileage and compares the resulting figure to historical averages. That methodology does not evaluate the reasonableness of the actual projects included in Peoples Gas's 2026 PRP plan and disregards the project-specific factors that determine project scope, feasibility, and execution

requirements, including location, constructability constraints, restoration requirements, labor conditions, customer-facing quantities, service installation requirements, execution risks, and overall complexity. By reducing a diverse portfolio of projects to a single program-level cost metric, the Panel's analysis obscures the operational realities that drive investment needs and fails to assess whether the individual projects proposed for 2026 are prudent and necessary. As explained in Section IV below, this benchmark-driven approach is also fundamentally inconsistent with the evidentiary standard the same AG Panel invokes elsewhere in this proceeding whenever a utility's own actual, project-specific cost evidence would otherwise control.

Further, the AG Panel's proposed $97.2 million disallowance was calculated against the prior approximately $210 million authorization that is no longer operative. Accordingly, the recommendation bears little relationship to the investment level now supported by the record and provides no meaningful basis for evaluating the prudence of the Company's revised 2026 PRP investment request.

Most importantly, Staff witness Mr. Seagle independently reviewed the same project documentation, cost support, and planning assumptions and expressly rejected the AG Panel's recommended disallowances, concluding that Peoples Gas's estimates and requested base revenue requirement for PRP work are reasonable. The Company's latest revisions to the 2026 and 2027 PRP plans rely on the same project-specific planning processes, cost-development methodologies, and supporting documentation that Staff previously reviewed and

found reasonable. As such, the revisions reinforce—rather than undermine—the basis for Staff's rejection of the AG Panel's proposed disallowances.

(2) PGL's two-tier contingency structure—consisting of allocated and unallocated contingency—is consistent with AACE International standards, does not double-count project-level and program-level contingency, and is trued up to actual costs through Illinois' ratemaking actualization process. The AG Panel's claimed inconsistency in PGL's contingency figures is a product of the Panel's own derivation methodology, not any inconsistency in the Company's presentation. Whatever the Panel's intent, presenting AG-derived values under the heading of variations "PGL has identified" improperly attributes to the Company an inconsistency of the Panel's own making. Accordingly, the AG Panel's proposed $71.06 million contingency disallowance should be rejected. Moreover, we also confirm that Peoples Gas has provided project-specific support for contingencies exceeding 10% to the satisfaction of Mr. Seagle.

(3) The PRP's schedule is feasible. The AG Panel's projection that retirement will not be completed until approximately 2049 rests on a model that the Panel admits does not incorporate PGL's planned ramp-up of PRP work. It likewise fails to account for the structural changes, secured contractor capacity, and Comprehensive Strategic Program Plan ("CSPP") that distinguish the PRP from the legacy System Modernization Program ("SMP") and a reasonable basis to conclude that the Commission's retirement directive can be achieved on schedule.

(4) There is substantial agreement on key aspects of the PRP and the path forward. For example, Staff, the AG, the City, and EDF do not challenge the prudence or necessity of the PRP at the program level and Staff finds the Company's implementation approach and strategic alliance contracting reasonable and prudent. Similarly, Peoples Gas and PIRG agree that the Commission should clarify whether CIPL can satisfy the retirement directive. Consistent with that position, the Company does not categorically reject CIPL but evaluates it on a project-specific basis—selecting CIPL where the relevant factors align and replacement or insertion where they do not—as recent project examples illustrate.

(5) The remaining proposals advanced by PIRG (repair and rehabilitation, NPAs, hydraulic feasibility, cost-effectiveness gating, relining, and reconsideration of the retirement mandate), CUB (targeted electrification study), and EDF (advanced leak detection, leak-data utilization, detailed reporting, financial incentives, and environmental justice) are unnecessary in light of the Company's existing practices, premature, inconsistent with the Commission's mandatory retirement directive, better suited to other proceedings, or some combination thereof. In particular, PIRG's assertion that the PRP produces a benefit-cost ratio of approximately 0.01 rests on a fundamentally flawed analysis that monetizes only avoided leak-repair costs while disregarding the full range of safety, reliability, operational, and environmental benefits associated with CI/DI retirement. Accordingly, these proposals provide no basis for restructuring the PRP or denying recovery of the Company's prudent PRP investments.

D. Sponsored Exhibits

Q. Are you sponsoring any exhibits with your surrebuttal testimony?

A. Yes. The following exhibits are attached to our testimony:

- NSG-PGL Ex. 31.1 is the complete breakdown of 2026 and 2027 costs and represents PGL's operative PRP request in this rate case. It includes the updated project listing and provides: (1) the base cost of the proposed PRP work; (2) the amount of project-level contingency associated with those estimates; (3) the separate program-level contingency; (4) the risks each category of contingency is intended to address; and (5) how those amounts relate to the total revenue requirement requested in this proceeding, as requested by the AG Panel.
- NSG-PGL Ex. 31.2 sets forth each project's allocated contingency, as requested by Mr. Seagle.
- NSG-PGL Ex. 31.3 is the 7/13/2026 meeting notes of the ESC regarding the adjustments to the forecasted 2026 and 2027 retirement targets and investment levels.
- NSG-PGL Ex. 31.4 is Peoples Gas's response to AG data request AG 9.05, which pertains to how PGL distinguishes and calculates contingency.
- NSG-PGL Ex. 31.5 is the AG's responses to Companies data requests NSG-PGL-AG 5.06, 5.07, and 5.08.

- NSG-PGL Ex. 31.6 is a Peoples Gas presentation titled "Cured in Place Liners," which provides an overview of CIPL technology, the Company's structured evaluation framework for assessing CIPL feasibility on a project-specific basis, the CIPL installation process, and detailed case studies of the Canalport and South Shop projects discussed in Section VIII demonstrating how the Company applies that framework in practice.

- NSG-PGL Ex. 31.7 is a compilation of PIRG's responses to Companies data requests regarding the PRP.

- NSG-PGL Ex. 31.8 is an Advisory Bulletin issued by PHMSA on July 9, 2026 entitled "Pipeline Safety: Guidance for Enhancing the Effectiveness of Distribution Integrity Management Programs."

II. PROGRAM-LEVEL AGREEMENT

Q. Before turning to the issues in dispute, please summarize the areas where Peoples Gas and the other parties agree regarding the PRP.

A. There is substantial common ground, and no party challenges the PRP at the program level. Staff witness Mr. Seagle confirms that the PRP is a Commission-directed, safety-driven initiative to retire CI/DI main under 36 inches by 2035, and that the Company is appropriately transitioning from a geography-based approach to a piping-system-level, risk-based prioritization framework using advanced probabilistic tools. Staff Ex. 4.0 at 8, 11–12. Staff further finds that implementing the program primarily through low-pressure ("LP") to medium-pressure ("MP") conversions while keeping meters inside is "the most reasonable choice" given the retirement directive, and that the Company's strategic

alliance contracting process was competitive, well-documented, and prudent, identifying no deficiencies warranting disallowance. *Id.*, at 14, 15.

The AG Panel likewise does not challenge the need for or the design of the PRP, acknowledges that PGL has made an effort to design the PRP to address gaps in its prior programs, and supports the process improvements reflected in the parties' stipulation and settlement. AG Ex. 2.00 at 19; AG Ex. 4.00 at 55.

The City and EDF address reporting, NPAs, and methane issues but do not dispute the program's structure or the retirement directive. *See generally* COC Exs. 1.0, 2.0; EDF Exs. 1.0, 2.0.

We appreciate this consensus, and we do not understand these fundamentals to be in dispute.

Q. In direct testimony, the AG Panel asserted that Peoples Gas's Project Authorization Requests ("PARs") "do not contain the changes in contractor pricing that PGL cited" as justification for refined cost estimates, and that "[w]hile each PAR does contain an old and new cost estimate, they do not contain the changes in contractor pricing." AG Ex. 2.00 at 28. Does the Panel maintain this position in rebuttal?

A. No. In rebuttal, the Panel effectively concedes that its criticism was based on a misunderstanding of the contractor pricing information reflected in the PAR forms presented in NSG-PGL Exs. 3.17 REV and 17.2. Specifically, the Panel acknowledges that it misinterpreted the date associated with the contractor cost estimates, which Peoples Gas explained represents the first date the unit rates were used rather than the date the estimate itself was prepared. *See* AG Ex. 4.00 at 26 (citing NSG-PGL Ex. 17.0 at

30–31). As a result, the factual premise underlying the Panel's direct testimony claim—that the PARs did not reflect the contractor pricing changes cited by the Company—has been shown to be incorrect.

Q. Is there agreement on any of the issues raised by PIRG?

A. Yes. Although we disagree with much of PIRG's analysis, there is an important point of convergence: both Peoples Gas and PIRG ask the Commission to clarify whether CIPL can satisfy the retirement directive in the 2024 SMP Investigation Order.[1] As we explained in rebuttal, the Company is not categorically opposed to repair and rehabilitation technologies; rather, the regulatory uncertainty regarding whether such technologies "retire" CI/DI pipe within the meaning of the directive necessarily constrains their deployment at the present time in the PRP. *See* NSG-PGL Ex. 17.0 at 100. We welcome Commission direction on this threshold question, which will inform the Company's program planning going forward.

Q. Have any parties newly raised or materially shifted their positions relative to their direct testimony?

A. Yes. First, on rebuttal, the AG Panel maintains its proposed $97.2 million cost disallowance and its $71.057 million contingency disallowance, recasts its cost analysis around the implied "$10 million per mile" figure, introduces a new analysis of "hidden" Excel data in NSG-PGL Ex. 17.3, and performs a Class 5-to-Class 3 PAR cost analysis. *See* AG Ex. 4.00 at 8–9, 11–12, 23, 37–34. As indicated, subsequent to the filing of Staff

[1] PIRG witness Mr. Lewnard "commend[s] PGL for requesting this clarification from the Commission" and he "likewise recommend[s] that the Commission issue such a clarification." PIRG Ex. 8.0 at 13.

and intervenor rebuttal testimony, the Company updated its PRP forecast for work and associated costs during 2026 and 2027, adjusting the 2026 retirement target to approximately 14 miles at an adjusted investment level of approximately $120 million. Because this revision was not authorized until after Staff and intervenor rebuttal testimony was filed, it is presented here for the first time. This development materially affects the basis for the Panel's recommended $97.2 million disallowance, which was calculated against the Company's prior approximately $210 million 2026 PRP forecast rather than the updated forecast supported by actual field-execution data and construction experience. We address the AG Panel's cost-related criticisms and underlying methodology in Sections IV and V below.

Second, Mr. Seagle has withdrawn his concerns regarding the 37 placeholder PRP projects in light of the Company's supplemental documentation, and now rejects the AG's large PRP capital cost disallowances—a significant development that we address in Section VII.

Third, PIRG witnesses Drs. Jonathon Lesser and Charles Feinstein newly assert in rebuttal that PGL's PRP investments produce a benefit-cost ratio of approximately 0.01 (one penny of quantified risk reduction per dollar spent), and recommend that the Commission reconsider the retirement mandate itself; this is their most significant new argument and we address it in Section IX.

Fourth, PIRG witness John Lewnard asserts in rebuttal that CIPL meeting the ASTM F3777-25 standard rehabilitates CI/DI pipe with a 50-year or greater service life and therefore satisfies the retirement directive; we respond in Section VIII.

Fifth, CUB witness Mr. Velez clarifies that his proposal requests a study and a plan, not a program; we address this reframing in Section XI.

III. THE FORECAST UPDATE

Q. You indicate that the Company has revised its 2026 and 2027 forecast. Please explain that revision and its significance.

A. For clarity, I'll start by quantitatively showing a summary of this forecast update:

		Current Request	
		2026	**2027**
Quantities within each calendar year	Main Install (miles)	59	90
	Service Install (count)	6,087	9,409
	Customer Facing (count)	4,674	13,233
	CI/DI Retirement (miles)	14	50
Dollars within each calendar year, shown in millions	Base Project Costs	$103.9	$251.1
	Customer Facing Costs	$10.0	$42.3
	Allocated Contingency – project based	$1.2	$3.6
	Unallocated Contingency – project based	$4.6	$22.5
	Unallocated Contingency – program based	$0	$0
	Total	$119.7	$319.5

The Company is updating its rate request based on this latest forecast update for PRP.

The revised requests are lower than the amounts presented earlier in this proceeding and represent the level of investment that Peoples Gas can prudently, safely, and reliably execute during 2026 and 2027 based on demonstrated field productivity, secured and projected workforce, and the sequencing necessary to coordinate main installation, customer-facing work, and restoration. These revisions reflect prudent utility

planning. As actual field-performance data and other project-execution information became available, Peoples Gas refined the scope of work that could reasonably be executed and adjusted annual investment levels accordingly to align with demonstrated construction capacity, available resources, and known execution constraints.

Q. Please describe what's driving this forecast update.

A. The forecast update includes both routine monthly forecasting updates and a more comprehensive revision of project schedules based on current projections of available resource capacity. Specifically, the update incorporates actual expenditures and schedule performance through June 2026, updated forecasts for remaining project costs, revised project schedules, updated assumptions regarding customer-facing workforce availability, and current projections for 2027 resource capacity. Based on these updated inputs, Peoples Gas sized the program to its secured and forecasted construction workforce and sequenced main installation work so it does not outpace the customer-facing and restoration activities required to complete retirement work safely and efficiently.

Q. Please elaborate on the secured and forecasted construction workforce updates that are driving the schedule forecast updates.

A. As discussed in our supplemental direct testimony (NSG-PGL Ex. 3.0 REV SUPP02 at 4–15) and rebuttal testimony (NSG-PGL Ex. 17.0 at 19–27), the Company has been evaluating resources needed and available specifically for the customer facing work (regulator installation and re-lights) and associated service retirements (whether internally plugged during the re-light activity or physically cut after the re-light activity). As described in the PRP whitepaper (NSG-PGL Ex. 3.21 at 36–38), this workforce is

technical, requiring time to recruit, onboard, and train. Recognizing this lead time, the Company took near-term measures to develop this resource pipeline and evaluated a range of workforce development and resourcing strategies to build sustainable construction capacity.

In our supplemental direct testimony (filed in mid-April), we described the Chicago Labor Market Analysis. As a refresher, the CLMA (exhibit reference) excluded employees represented by Gas Workers Union Local 18007, Utility Workers of America, AFL-CIO ("Local 18007"), which is a signatory to Peoples Gas. The CMLA highlighted that the Chicago region faces skilled-labor risk and that large regional projects have effectively established a "regional labor price floor" through the incentive packages they offer. At that time, the project cost estimates did not include premiums specifically driven by the factors described in the CLMA.

Since receiving the CMLA, the Company confirmed its currently secured resources, with these resources starting the customer facing work in May. As the Company has continued to evaluate mitigation strategies to support both near-term and long-term resource needs, and has monitored production over the past two months, it has refined its workforce strategy to support the forecasted increase in construction activity beginning in 2027. The Company's strategy includes continued investment in workforce development, recruiting, onboarding, and training of qualified personnel, while maintaining the flexibility to supplement resources, as needed, to meet program objectives. The forecast update reflects these workforce development initiatives, associated recruiting and onboarding costs, and market-based labor cost assumptions. In addition to incorporating these workforce initiatives into the forecast, the project

schedules were updated to align with the currently secured resources and forecasted resource increases based on the mitigating strategies in place. This update to the project schedules helps ensure that the main installation activity does not out-pace the customer facing activity, which would lead to extended construction durations (longer periods of disruption in front of customer premises).

Q. Are there any other notable changes with this forecast update?

A. Yes. The updated forecast also includes an estimated $8 million cost to establish the strategic alliance contracts. Peoples Gas proposes to amortize that amount over the five-year term of the contracts rather than recover the full amount in a single year. Consistent with that treatment, the updated 2027 forecast includes approximately $1.6 million associated with the strategic alliance implementation costs. This approach appropriately aligns recovery of the contractor-establishment costs with the period over which the contracts will provide the workforce capacity necessary to execute the PRP. As a result, customers will bear these costs ratably over the same period in which they receive the associated benefits, consistent with longstanding ratemaking principles that match costs and benefits over the useful life of a multi-year investment or commitment.

Q. Does this forecast update add projects to this request?

A. No. The forecast update does not add any projects to this rate request.

Q. Does this forecast update change PAR documentation previously reviewed by the intervenors?

A. No. The forecast update does not change the PAR documentation previously provided and reviewed. As part of each forecast update, Project Managers compare updated forecasted project costs to the amounts authorized in the applicable PARs. Given the inclusion of out-of-state labor in the forecast, a number of projects with main installation work scheduled for 2027 may now be forecasted above their current PAR-authorized amounts. Those variances, however, do not alter the previously issued PAR documentation and will be addressed through the Company's established processes for variance documentation, project change requests, contingency releases, additional forecast updates, and PAR reauthorization, as appropriate.

Q. Does this forecast update change other data and documentation previously provided?

A. Yes. The forecast update incorporates actual expenditures through June 2026 and revised project schedules that levelize work based on available resources. As a result, the timing of project expenditures has changed and investment levels have been redistributed across years for certain projects. The update also incorporates revised project risk assessments and associated allocated contingency calculations based on information available through June 2026.

To reflect these updates, the Company is providing NSG-PGL Ex. 31.1, which contains the most current project listing and annual investment amounts. The exhibit itemizes every component of the Company's requested 2026 and 2027 investment levels,

including direct project costs, customer-facing costs, allocated contingency, and unallocated contingency.

This exhibit provides a single, comprehensive source for the Company's requested investment levels. The Commission need not reconcile figures appearing in multiple exhibits, filing stages, or data snapshots to determine the Company's requests. Rather, the Company's 2026 and 2027 requested investment levels are presented once, in one place, and every dollar included in those requests is identified and traceable from the individual project-cost component level through the total requested investment amount.

Q. How has this forecast update been reviewed within the PRP Program Management Office ("PMO") structure?

A. The forecast update has been reviewed by the Executive and Co-Executive, as well as the ESC of the PRP PMO. The quantity projections, resource need and availability assumptions, as well as annual cost updates were reviewed. *See* NSG-PGL Ex. 31.3 (7/13/26 ESC meeting notes).

IV. RESPONDING TO THE AG PANEL'S COST OBSERVATIONS

Q. You noted that the AG Panel's recommendations rest on a methodology that misapplies the Company's exhibit data. Before detailing that, why does the Company address these recommendations even though it has presented an updated, lower request?

A. For two reasons. First, the updated request stands on its own and is not a response to the AG Panel; the Company would have sized the program to its secured and forecasted workforce and required sequencing regardless of any party's litigation position. Second,

and separately, the AG Panel's cost-per-mile and contingency recommendations are built on specific analytical errors that, if left uncorrected in this record, could be repeated in future PRP proceedings. Correcting them here protects the integrity of the record and of the methodology that will govern the program through completion. The updated request and the response to the AG Panel are therefore independent: the first is prudent program management; the second is a correction of the record.

Q. Please explain how the AG Panel derived the historical unit-cost benchmark that underlies its proposed $97.2 million disallowance.

A. The Panel's proposed disallowance was calculated using the Company's earlier 2026 investment request of approximately $210 million. Relying on a historical unit-cost benchmark of approximately $5.37 million per retirement mile, the Panel concluded that only approximately $112.8 million (*i.e.*, $5.37 million times 21 retirement mile) should be authorized in rates and treated the remaining approximately $97.2 million as unsupported. AG Ex. 4.00 at 12.

Q. Given the Company's forecast update, how could that update effect the AG Panel's proposed disallowance?

A. The forecast update materially changes the inputs to the AG Panel's calculation. Using the Panel's stated benchmark of approximately $5.37 million per retirement mile and the updated forecast of approximately 14 retirement miles in 2026, the resulting benchmark amount would be approximately $75.2 million. Comparing that amount to the Company's updated 2026 PRP request yields a difference of approximately $44.8 million.

This comparison demonstrates that the magnitude of the AG Panel's proposed disallowance is highly sensitive to changes in the Company's forecast. More importantly, however, the exercise does not remedy the fundamental flaws in the Panel's methodology, which relies on a single project benchmark that is not representative of the PRP as a whole and does not provide a reasonable basis for determining the prudence of the Company's requested investment levels.

Q. From reviewing the AG Panel's rebuttal testimony, please summarize your observations regarding the cost category of review.

A. The AG Panel appears to conflate total project costs with the timing and allocation of individual project-cost components across years. AG Ex. 4.00 at 22–25, 31–32. As a result, the Panel concludes that Peoples Gas has not sufficiently justified certain costs contributing to its annual cost-per-retirement-mile calculation. To clarify the Company's cost presentation, NSG-PGL Ex. 31.1 identifies the specific project-cost components included in each calendar year. The remainder of this section addresses the AG Panel's principal cost-related criticisms, including its treatment of project costs, contingency, and annual cost-per-retirement-mile calculations.

Q. Is the Panel's comparison of PGL's updated costs to an implied per-mile benchmark an appropriate measure of prudence?

A. No. The Panel's benchmark comparison is not an appropriate measure of prudence. A single per-mile cost metric necessarily oversimplifies a complex portfolio of projects whose costs are driven by project specific scope with contractor, labor, material, permitting, and overhead costs estimated based on that scope and spread over time based

on the project schedules. The Company has identified and quantified these drivers through project-specific estimates, and Staff witness Mr. Seagle reviewed the underlying project documentation, cost support, and planning assumptions and concluded that Peoples Gas's estimates are reasonable. *See* Staff Ex. 13.0 at 6. Indeed, Mr. Seagle expressly rejected the AG Panel's recommended $97.2 million disallowance and reaffirmed that the Company has provided a sufficiently robust, transparent, and well-supported record for the Commission to evaluate the prudence and reasonableness of its PRP investment requests. By contrast, the Panel's aggregate benchmark approach, rather than evaluation of project-level evidence, does not assess whether the costs of any particular project are reasonable under the actual conditions of its execution.

Q. Does the Panel's reliance on historical SMP annual unit costs provide a reliable benchmark for evaluating PRP costs?

A. No. The Panel's benchmark assumes that the SMP and the PRP involve the same scope of work, construction methods, operating conditions, and project timing, but the record demonstrates otherwise. AG Ex. 4.00 at 15–20. The benchmark fails to account for several material differences, including:

- **Different customer-facing scope.** Under the SMP, Peoples Gas generally relocated every customer meter outside and installed a new meter at each premise. Under the PRP, meter locations are evaluated individually, existing meters are left in place where doing so accelerates CI/DI retirement, and existing temperature-compensated meters are reused when relocation is warranted. These changes materially affect the scope of work and labor requirements.

- **Different construction methods.** The PRP maximizes the use of directional boring for polyethylene installation where feasible, reducing open-cut trenching and associated restoration costs compared to historical practices.
- **Different mileage composition.** The PRP forecasts are specifically tied to CI/DI retirement miles, whereas the SMP included work on other LP pipe materials. As a result, the annual cost-per-mile figures are not directly comparable.
- **Different project timing and cost recognition.** The PRP's 2026 forecast reflects a program that is still ramping up. By contrast, SMP unit costs from years such as 2022 reflected retirements associated with main-installation work performed in prior years. For example, projects retired in 2022 often had their main-installation costs incurred in 2021. The PRP does not have a comparable volume of 2025 main-installation work supporting 2026 retirements.
- **Different operating environment.** The PRP is being executed under current City of Chicago permitting and restoration requirements and in an environment characterized by documented skilled-labor shortages and competition from major regional infrastructure projects. These conditions did not exist to the same extent during the historical SMP period and are not reflected in the Panel's benchmark.

Because the Panel's benchmark does not account for these material differences, it cannot provide a reliable basis for determining whether the costs reflected in the Company's project estimates are reasonable or whether the Company's requested PRP investment levels are prudent.

Q. In trying to analyze the cost data and cost-per-retirement mile benchmark, the AG Panel asserts that PGL's claim of $77.7 million in "front-loaded or fixed" 2026 costs is unsupported, noting that Management & Design ("M&D") costs "actually decreased" from Class 5 to Class 3 estimates. AG Ex. 4.00 at 31–32. How do you respond?

A. These observations by the AG Panel highlight the confusion regarding total project costs and how those costs are spread over time. Specifically, the observation that the M&D costs decreased in the AG Panel's analysis of the Class 5 to Class 3 estimates comparisons is a total project cost comparison regardless of how those costs are spread over time. The observation that on an annual per-retirement mile basis, the M&D costs are contributing to a greater per-retirement mile basis in 2026 is also true. Additionally, the Panel's analysis rests on an incorrect premise: that front-loaded costs are synonymous with, or limited to, the M&D line item in PAR-level data. They are not. Front-loaded costs when comparing annual per-retirement mile rates also include costs associated with main installation and service installation for projects that do not have retirement until 2027.

In response to AG data request AG 7.01 (AG Ex. 4.11), the Company identified the specific categories comprising the $77.7 million in front-loaded and fixed costs. Those categories are documented in the record. The Panel's assertion that the $77.7 million figure lacks support highlights its focus on a single line item (M&D) and misunderstanding of the differences between total project costs and how costs are spread over time.

Q. With this surrebuttal and given the Company's forecast update, are you providing additional information to further clarify how front-loaded and fixed costs contribute to a higher cost-per-retirement mile in 2026 compared to historical years?

A. Yes. While annual historical unit cost comparisons are not appropriate for prudency reviews and cannot substitute for a project-specific prudence review, Peoples Gas has prepared an annual view by cost type, allowing the Commission to evaluate the contribution of each factor independently. *See* NSG-PGL Ex. 31.2. PGL recognizes that annual unit cost data can be insightful when properly structured. With the annual unit cost data, the Commission will observe that the direct contractor costs and the M&D costs are the two cost components driving over 70% of the increase when compared to historical neighborhood data on an annual per-CI/DI-retirement mile basis. The annual unit rate increase from these two cost components is driven by how these two cost components are spread over time, relative to the CI/DI retirement denominator for the year. Notably, when comparing the cost per install mile for PRP in 2026 to historical neighborhood cost per install mile (escalated annually at a modest 3%), the Commission will observe a decrease of approximately 9%.

Q. Does this annual per-retirement mile analysis address the AG Panel's assertion that PGL's claimed PRP cost drivers are "unidentified, unquantified, or otherwise unsupported" (*id.*, at 18), as presented in its comparison table (AG Ex. 4.00 at 19–20, Figure 2)?

A. Yes. By reviewing the data structured and organized in a manner to support annual per-retirement mile analysis, the AG Panel will observe that the increase when comparing

2026 forecasts to historical annual forecasts is driven by the cost categories previously discussed, contractor costs (particularly the front-loaded main and service installation) and M&D (fixed costs). Moreover, the project-level documentation identifies, quantifies, and supports the project costs. Mr. Seagle reviewed the project-level documentation and concluded that PGL's estimates are reasonable, finding that "[t]he Company provided a robust, clear, and transparent record for this Commission to make a determination of the reasonableness of the costs and the prudence of PGL's business decision in the selection and estimation of cost for PRP projects." Staff Ex. 13.0 at 6. The AG Panel's characterization of these cost drivers as "unsupported" is therefore not a function of missing documentation; it reflects a misalignment regarding the weight and significance of the project-specific documentation that PGL provided.

Q. Is there an inconsistency in how the AG Panel evaluates cost evidence in this proceeding?

A. Yes. It mirrors the inconsistency that Companies witness Mr. Arana identifies in his surrebuttal testimony addressing North Shore's Clavey Road project. *See* NSG-PGL Ex. 32.0 at 34–36. For Clavey Road, where North Shore seeks recovery of approximately $1.2 million in costs that Staff witness Mr. Seagle has confirmed were reasonable, the AG Panel dismisses North Shore's actual, known, competitively bid, and categorically documented project costs in favor of a generic, national cost figure drawn from a 2017 American Petroleum Institute ("API") study of nationwide oil-and-gas infrastructure investment, later supplemented with Oil & Gas Journal and U.S. Energy Information

Administration ("EIA") market data—sources with no connection to North Shore, to Illinois, or to that project. *Id.*, at 35 (citing NSG-PGL Ex. 4.24 at 65–68).

For the PRP, the Panel again discounts company-specific project information, but in a different way. It relies on a program-level unit-cost benchmark that divides aggregate historical costs by aggregate retirement mileage. AG Ex. 4.00 at 11–12. Although the Panel reviewed project-level cost information, it ultimately places greater weight on a program-level benchmark comparison than on the project-specific engineering, cost-estimating, and contractor-pricing information supporting the Company's forecasts.

Q. Please describe this inconsistency in greater detail.

A. As Mr. Arana explains, the AG Panel's analysis of the PRP is built on a comparison between planned PRP unit costs and historical SMP unit costs derived from Peoples Gas's prior program experience. *See* NSG-PGL Ex. 32.0 at 34–35 (citing AG Ex. 2.00 at 24; AG Ex. 4.00 at 14). The Panel also rejects broader explanations for cost differences—such as inflation, ramp-up effects, or industry-wide cost escalation—and instead calls for project-level support. *See* AG Ex. 4.00 at 17, 27.

Yet the Panel's recommended $97.2 million PRP disallowance ultimately rests on a high-level historical comparison that does not evaluate the reasonableness of any individual PRP project. The analysis compares aggregate program costs and aggregate retirement mileage without accounting for the specific engineering, scope, contractor pricing, project schedules, and construction circumstances reflected in the underlying PRP projects.

As discussed above, the benchmark itself is derived from a different program at a different stage of execution (steady rather than ramp-up), and it does not reflect current labor-market conditions, even though the AG Panel has confirmed that it inflated historical SMP costs to 2026 dollars for purposes of the comparison. *See* NSG-PGL Ex. 31.5 (AG response to Companies data request NSG-PGL-AG 5.06(c)). More fundamentally, in response to Companies data request NSG-PGL-AG 5.06, the AG Panel itself confirmed that "the main purpose of our analysis" was to "[s]how[] the magnitude of the difference to give helpful context" and to "frame and compare the evolution of historic costs," expressly disclaiming any contention "that historical costs establish the precise reasonable cost of every single future project." AG Ex. 4.00 at 14; NSG-PGL Ex. 31.5 (AG response to Companies data request NSG-PGL-AG 5.06(a)). Having disclaimed any project-specific precision for its own benchmark, the Panel cannot simultaneously rely on that same benchmark to derive a specific $97.2 million disallowance targeted at particular PRP cost estimates. At the same time, the record contains detailed project-specific information for the proposed PRP investments, including Class 3 estimates, engineering analyses, contractor bids, and supporting project documentation. Similarly, the record for Clavey Road contains actual project costs and project-specific support. Despite those records, the Panel relies on generalized benchmark comparisons in both contexts rather than evaluating the project-specific evidence on its own merits.

Q. The AG Panel identifies isolated instances where internal PGL labor costs increased 100% to nearly 1000% from Class 5 to Class 3 estimates, while contractor labor increased more modestly. AG Ex. 4.00 at 29–31. Does this demonstrate cost unreasonableness?

A. No. Many Class 5 estimates for internal labor categories reflected nominal or placeholder-level figures because those categories were not yet scoped at that early planning stage, and the resulting percentage increases are mathematically inevitable artifacts of starting from a low base value rather than evidence of cost escalation. In response to Companies data request NSG-PGL-AG 5.07(c), the AG Panel indicated that it did not identify a literal zero-dollar Class 5 entry within the specific dataset underlying its cited percentage figures, noting that a percentage increase could not otherwise be calculated. The Company does not dispute that clarification, and it does not change the underlying point: a nominal or minimally scoped Class 5 placeholder value—whether zero or a small non-zero figure—produces a disproportionate percentage increase once the category is fully scoped and estimated at Class 3, without reflecting any actual escalation in cost. *See* NSG-PGL Ex. 31.5 (AG response to Companies data request NSG-PGL-AG 5.07).

To illustrate: if a Class 5 estimate contains $5,000 as a placeholder for internal project management labor, and the Class 3 estimate refines that to $50,000 based on actual engineering analysis of scope, duration, and staffing requirements, the resulting 900% increase is an artifact of the placeholder methodology, not evidence that internal labor cost estimates are unreasonable. The relevant question is whether the $50,000 Class

3 figure is reasonable for the work required—not whether it represents a large percentage increase over an acknowledged placeholder.

When examined in dollar terms rather than percentages, internal labor represents a consistent proportion of overall project costs in the Class 3 estimates. This is precisely what one would expect: as estimates mature from conceptual (Class 5) to more detailed engineering (Class 3), all cost categories are refined from placeholders to engineering-based quantities. That some categories were previously understated as placeholders in a Class 5 estimate is completely normal and does not render the refined estimates imprudent.

Q. The AG Panel further contends that, in moving from a Class 5 to a Class 3 estimate, PGL "consistently sees increases in contractor and PGL labor and decreases in permitting costs," and it treats the disparity between the percentage increase in PGL labor and the percentage increase in contractor labor as evidence that PGL's estimating process is unreliable. AG Ex. 4.00 at 30. Is the Panel's percentage-based comparison methodology sound?

A. No. The Panel's methodology is flawed for a reason distinct from, and in addition to, the placeholder-driven distortions discussed above. The preceding discussion addresses the most extreme percentage increases in the Panel's Figure 3 data—outliers approaching 700% to nearly 1000%—which resulted from near-zero or placeholder Class 5 values for categories not yet scoped at that early planning stage. But there is a separate, independent flaw in the Panel's methodology; even where Class 5 estimates reflect substantive, non-placeholder figures, percentage comparisons must be interpreted carefully. The AG Panel

assumes that changes in PGL Labor and Direct Contractor Costs should generally move in similar proportions as estimates mature. However, that assumption does not account for how costs are developed, refined, and categorized between Class 5 and Class 3 estimates. Costs may be recategorized based on improved project definition and general estimate maturity.

As noted in my rebuttal testimony (NSG-PGL Ex. 17.0, lines 964–976), PGL was aware of a cost categorization change between its Class 5 estimates and Class 3 estimates between the permitting/other category and the labor category (Class 5 estimates included an estimate line item in the permitting/other category, whereas the estimate line item was appropriately captured in labor as part of the Class 3 estimate preparations). Differences in percentage movements among individual cost categories do not, standing alone, demonstrate that the underlying estimate is unreliable.

The relevant metric for evaluating the reasonableness of PGL's cost estimates is the change in Total Project Cost, not the movement of any individual cost category. Some fluctuation across categories—including the decreases in permitting costs that the Panel notes—is expected as an estimate matures from Class 5 to Class 3; that is the purpose of progressive estimating. By the Panel's own calculation, the weighted average Total Project Cost change across the 27 assessed PAR projects was 21%. AG Ex. 4.00 at 29 (Figure 3). Under AACE International Recommended Practice 97R-18, a Class 5 estimate carries an expected accuracy range of -20% to -50% on the low end and +30% to +100% on the high end, while a Class 3 estimate carries an expected accuracy range of -10% to -20% on the low end and +10% to +30% on the high end. A 21% increase as an estimate matures from Class 5 to Class 3 therefore falls comfortably within these

recognized industry accuracy bands and does not indicate cost unreasonableness or estimating irregularity.

Q. The AG Panel raises a concern regarding potential double recovery for the Cragin Phase 16 project, noting that it appeared on PGL's project list in the 2023 rate case and also appears in this proceeding. AG Ex. 4.00 at 32–33. Is there any double recovery?

A. No. PGL's project list in the test year 2024 rate case (Docket Nos. 23-0068/23-0069 (cons.)) included Cragin Phase 16 at an early planning stage. However, inclusion of a project on a forward-looking project list does not place project costs into rate base or authorize recovery of those costs. More importantly, the Commission ultimately disallowed recovery of SMP costs in that proceeding. As a result, no Cragin Phase 16 costs identified as part of the SMP portfolio would have been recovered through the test year 2024 rate case.

The costs for Cragin Phase 16 at issue in this proceeding reflect subsequent engineering, procurement, and construction activities and are being evaluated based on the record developed in this case. In all events, the Company's actualized plant additions process prevents double recovery because only costs that have not previously been included in rate base can be reflected in the current request. Accordingly, there is no possibility that Cragin Phase 16 costs are being recovered twice.

Moreover, FTI Consulting's independent review of all 81 PARs produced in this proceeding confirmed no duplicative recovery. NSG-PGL Ex. 27.7. The Panel has not identified any specific dollar amount that it believes has been recovered twice—it has

merely observed that the project name appears in both proceedings, which is entirely expected for a multi-year construction project that progresses through planning, engineering, and execution across rate case cycles.

Q. The AG Panel concedes that Peoples Gas's SMP request was partially disallowed in the 2024 test year rate case but maintains that "PGL has not provided sufficient evidence to address our identified concerns about double recovery in this rate case." AG Ex. 4.00 at 33. Why is that an untenable position?

A. Because that assertion is inconsistent with both the scope and the outcome of the Commission's rehearing order in PGL's test year 2024 rate case. The AG was an active participant in both the underlying proceeding and subsequent rehearing, where the Commission made clear that rehearing was limited to 2023 SMP work-in-progress ("WIP") and emergency work. The Commission expressly stated that rehearing would "focus exclusively on 2023 SMP work-in-progress and emergency work," while broader neighborhood SMP issues remained subject to the Commission's pause and separate review in the SMP investigation docket. *See N. Shore Gas Co., et al.,* ICC Docket Nos. 23-0068/0069 (cons.), Order on Rehearing (May 30, 2024) ("TY24 Order on Rehearing"), at 16.

Moreover, the AG Panel expressly acknowledges that the Cragin Phase 16 project was not included in the 2023 QIP reconciliation. AG Ex. 4.00 at 32 ("we agree that the Cragin Ph 16 project was not in the 2023 QIP Reconciliation"). That admission is significant because the principal concern identified by the Commission on rehearing was the potential overlap between certain WIP projects and projects appearing in the 2023

QIP reconciliation filing. By the AG Panel's own admission, Cragin Phase 16 was not among those projects. Accordingly, the specific concern that animated the Commission's rehearing analysis does not apply to Cragin Phase 16.

The Commission ultimately denied Peoples Gas's request to increase rate base by approximately $82.8 million for SMP WIP in the test year 2024 rate case. TY24 Order on Rehearing at 49. In doing so, the Commission concluded that Peoples Gas had not sufficiently demonstrated that the proposed WIP investments were distinct from amounts identified elsewhere, including the extent to which WIP projects overlap with the Company's 2023 QIP projects. *Id.*, at 50. The Commission therefore declined to approve *any* rate base or revenue requirement associated with those projects.

Equally important, neighborhood SMP projects outside the limited category of 2023 WIP were not before the Commission on rehearing *at all*. The Commission repeatedly emphasized that the rehearing was limited in scope and did not reopen the broader neighborhood SMP program. Projects outside that limited scope remained paused and were deferred to subsequent proceedings, including the SMP investigation and future rate cases. *Id.*, at 16.

Thus, the AG Panel's suggestion that Peoples Gas has failed to address a risk of double recovery overlooks a fundamental fact: the Commission did not authorize recovery of the disputed SMP WIP investments, and other neighborhood SMP projects were expressly excluded from the rehearing's scope. There can be no double recovery where the prior proceeding denied recovery of the costs at issue and where other neighborhood projects were never approved for recovery through the rehearing order.

Lastly, the Commission expressly recognized that Peoples Gas could seek recovery of adequately supported costs in future proceedings. *Id.*, at 78 ("This Order does not modify the Company's options for lawful recovery of adequately supported costs in later proceedings."). This proceeding is precisely that type of review. Peoples Gas is not seeking recovery of costs previously approved and included in rates; it is seeking recovery of costs that were either denied recovery in the rehearing proceeding or never authorized for recovery in the first place. A cost cannot be recovered twice when it was never recovered the first time.

Accordingly, the AG Panel's double-recovery claim lacks any factual basis. The Commission neither approved the disputed WIP costs on rehearing nor authorized recovery of the broader neighborhood SMP projects outside the rehearing's limited scope. As a result, there is no prior recovery from which any double recovery could arise.

Q. The Panel also points to alleged discrepancies in spreadsheet data and project counts. AG Ex. 4.00 at 24–25. Do those observations demonstrate imprudence?

A. No. Those observations reflect misunderstandings of the underlying documentation rather than evidence of unreasonable costs.

For example, the Panel's claimed discrepancy between 160 and 139 projects arises because the underlying workbook includes all projects with 2026 or 2027 cash-flow activity, including projects whose in-service dates occur later, whereas the summary project list includes only projects expected to be placed in service during 2026 or 2027. The two tabs therefore serve different purposes and are not inconsistent.

More broadly, these spreadsheet-based calculations suffer from the same flaw as the Panel's benchmark analysis: they focus on arithmetic comparisons and aggregate metrics rather than evaluating the prudence of individual projects. The relevant question is not whether the project count or retirement target is 21 miles, 14 miles, or some other amount, but whether the costs included for the projects actually planned are reasonable given their scope, constructability requirements, labor conditions, restoration obligations, and execution risks.

Q. While not directly in context of the AG Panel's cost category discussion, the AG Panel characterizes the PRP as "yet another revision to a long-existing initiative that Peoples Gas has historically mismanaged with missed targets and broken commitments." AG Ex. 4.00 at 8. How do you respond?

A. The PRP is not merely an incremental revision to the SMP; it represents a fundamental restructuring of how Peoples Gas designs, plans, procures, and executes CI/DI retirement. The structural reforms embedded in the PRP—including piping system based grouping of assets, strategic alliance contracting, the CSPP, a dedicated PMO, and enhanced program controls—did not exist under SMP.

These changes respond to the Commission's direction. In its 2024 SMP Investigation Order (Docket No. 24-0081), the Commission found that PGL's prior program governance was inadequate and directed the Company to develop and implement the specific program management enhancements that are now embedded in the PRP framework. *See* 2024 SMP Investigation Order at 85–86. The PRP is therefore not the Company's unilateral decision to "revise" a past program; it is the Company's

direct genuine response to the Commission's directive to build a fundamentally different program architecture.

Past program performance under different governance structures, in pursuit of different policy objectives, and built on different cost-recovery mechanisms does not establish that the current cost estimates—developed under new enhanced governance with PMO oversight and aligning with industry practices of Class 3 estimating—are imprudent. The relevant question is whether PGL's current estimates, prepared under the PRP's reformed governance framework, are reasonable for the projects proposed. Staff witness Mr. Seagle reviewed those estimates in detail and concluded they are. Staff Ex. 13.0 at 6.

Q. What are your conclusions regarding the AG Panel's cost category analysis and recommendations?

A. The Commission should reject the AG Panel's $97.2 million PRP disallowance. The Panel's recommendation is based on a broad historical comparison drawn from a non-representative annual comparison. As discussed above, that comparison does not account for material differences in project scope, construction methods, mileage composition, project timing, labor conditions, and other factors affecting annual costs. As a result, the Panel's annual cost-per-retirement-mile benchmark does not provide a reliable basis for evaluating the reasonableness of the Company's proposed investments.

By contrast, the record contains detailed project-specific information regarding the proposed 2026 PRP investments, including Class 3 estimates, competitively bid contractor pricing, engineering analyses, and extensive supporting documentation. That

information provides a direct basis for evaluating the reasonableness of the proposed investments. Because the Panel's analysis does not identify any particular PRP project, cost category, estimating assumption, or contractor price that is unreasonable, its proposed disallowance should not be adopted.

V. PROGRAM- AND PROJECT-LEVEL CONTINGENCY

Q. Staff recommends that Peoples Gas demonstrate how allocated contingencies are calculated (Staff Ex. 13.0 at 4), and the AG Panel recommends disallowance of $71.06 million in standalone PRP contingency for 2026–2027 (AG Ex. 4.00 at 36). How do you respond?

A. These recommendations are distinct and should be considered separately.

Staff does not recommend any contingency disallowance. Rather, Staff requests additional information regarding the methodology used to calculate certain allocated contingency amounts. Staff Ex. 13.0 at 5. In response, Peoples Gas is providing the calculations underlying those allocated contingencies, together with the rationale supporting them. *See* NSG-PGL Ex. 31.2. Accordingly, Staff's request has been fully addressed, and nothing in Staff's testimony provides a basis to adjust or disallow the Company's requested contingency. The record therefore supports recovery of the Company's full PRP contingency request.

The AG Panel, by contrast, recommends disallowance of approximately $22.8 million of PRP contingency in 2026 and $48.3 million in 2027. AG Ex. 4.00 at 9. For the reasons discussed throughout our rebuttal testimony (NSG-PGL Ex. 17.0 at 50–79) and this testimony, that recommendation should be rejected. The record demonstrates that the

requested PRP contingency is reasonable, appropriately supported, and necessary to reflect the risks and uncertainty associated with the planned work.

Q. How does Staff's position differ from the AG Panel's recommendation?

A. Staff does not challenge the inclusion of contingency, nor does Staff recommend any contingency-related disallowance.

As a threshold matter, Mr. Seagle confirmed that Peoples Gas provided adequate justification for both allocated and unallocated contingency. Staff Ex. 14.0 at 4. He specifically acknowledged that the project-specific information in the PARs adequately explained why allocated contingencies were included and stated that he has "no concerns regarding why an allocated contingency was added to a project." *Id.*

An example is included here as a review of how allocated contingency and unallocated contingency are developed at a project level:

- Schorsch Village Phase 16 (approximately 12% total contingency): $105,000 in allocated contingency for a restoration MOU, plus $448,000 in unallocated contingency at 10% of base costs. The allocated contingency was derived from the estimated incremental cost of full-depth roadway restoration beyond the standard trench-patch specification.

For each PRP project, the methodology is the same: unallocated contingency addresses general estimating uncertainty, while allocated contingency reflects specific, documented project risks. Because those risks have been identified, quantified, and supported in the record, Staff concluded that the Company has adequately explained why allocated contingency was included.

Nor does Mr. Seagle recommend any adjustment associated with allocated contingencies. *Id.*, at 5. His remaining request is simply for a calculation of the allocated contingencies included in the PARs and the method by which those allocated contingencies were calculated in order to make the record "as robust and complete as possible." *Id.*, at 4–5.

Q. Has Peoples Gas provided that additional information?

A. Yes. In response to Mr. Seagle's request, Peoples Gas is providing NSG-PGL Ex. 31.2, which shows the underlying calculations, assumptions, and methodology used to derive the allocated contingencies for the PRP projects at issue. The exhibit demonstrates that allocated contingency is not an arbitrary adder. Rather, it is derived from identifiable project-specific risks and quantified using project-specific assumptions, cost estimates, and risk assessments tied to those risks. The exhibit reflects the allocated contingency as of the current forecast (6/29/26 data date). Because construction is underway, these amounts differ from the illustrative figures referenced in direct and rebuttal testimony: as individual risks have been resolved, have not materialized, or have been reassessed, the associated allocated contingency has been updated through the Company's normal forecast process, as described in Section III. A difference between the amounts in this exhibit and the earlier examples is therefore expected, and reflects the forecast being kept current rather than any change in methodology. This same forecast-update process is why the Company did not revise the existing project PAR forms to present the calculations. The Company is considering incorporating additional allocated contingency calculation details within its PAR review packages moving forward.

Importantly, Mr. Seagle has already confirmed that, based on his review of the PARs, he has "no concerns regarding why an allocated contingency was added to a project" and does not propose any adjustment related to those contingencies. Staff Ex. 14.0 at 4–5. The remaining request was simply for additional information regarding the calculations underlying the allocated amounts. NSG-PGL Ex. 31.2 provides that information and further demonstrates that the Company's allocated contingency methodology is risk-based, project-specific, and supported by objective calculations. Accordingly, the record now contains both the rationale for the allocated contingencies and the calculations supporting them.

Q. What conclusion should the Commission draw from this evidence?

A. The record supports maintaining the Company's contingency approach and contingency amounts as reflected in its current PRP forecast. As discussed next, the AG Panel's recommendation to eliminate contingency should be rejected because it disregards the purpose of contingency, ignores Peoples Gas's documented risk-management process, and would underfund identifiable project risks during the most execution-intensive years of the PRP. Staff's narrower request for additional information regarding the methodology used to calculate certain allocated contingency amounts has now been fully addressed through NSG-PGL Ex. 31.2, and Staff does not recommend any contingency disallowance. Accordingly, the Commission should approve the Company's proposed contingency amounts, as revised with its current forecast.

Q. Does the AG Panel contest every aspect of PRP contingency?

A. No. The Panel states that the distinction between allocated and unallocated contingency is not at issue:

> The Panel understands that PGL allocates a small (~4%) percentage of its contingency request to specific, identifiable risks and that the remainder of the contingency is unallocated and intended to address risks that are known to exist but are not specific enough in nature to identify. This division of allocation is typical and not at issue here.

AG Ex. 4.00 at 35. Likewise, the Panel states that "the use of contingencies generally" is also "not at issue." *Id.*

Q. Why does the Panel maintain its recommendation to disallow "PGL's standalone contingency line items of $22,776,000 for 2026, and of $48,281,000 for 2027, for a total disallowance of $71,057,000.98" (*id.*, at 36)?

A. The Panel contends that our rebuttal testimony did not sufficiently explain "which of the PRP amounts in this case include contingencies and which do not, how those specific amounts were calculated, and for PGL to identify all contingency on a per-project basis and whether it is included in the PRP level contingency." *Id.* According to the Panel, Peoples Gas should additionally provide: (1) the base cost of the proposed PRP work; (2) the amount of project-level contingency associated with those estimates; (3) any separate program- or portfolio-level contingency; (4) the risks each category of contingency is intended to address; and (5) how those amounts relate to the total revenue requirement requested in this proceeding. *Id.*

Q. Has Peoples Gas responded to the informational requests identified by the AG Panel?

A. Yes. Although Peoples Gas disagrees with the implication that the record lacked sufficient support for its contingency request, this surrebuttal testimony provides the information the Panel states it would expect to see. Specifically, Peoples Gas identifies the base cost forecasts underlying the proposed PRP work, quantifies project-level and program-level contingency, explains the risks each category of contingency is intended to address, and demonstrates how those amounts relate to the overall revenue requirement request. In addition, to be fully responsive and leave no issue unaddressed, Peoples Gas has further quantified the principal drivers of program-level contingency and separately identified those amounts. This information is set forth in NSG-PGL Ex. 31.1. Accordingly, even accepting the Panel's stated informational requests for purposes of argument, the record now contains the information the Panel claims is necessary to evaluate the Company's contingency proposal.

Q. In addition to the data being provided, please explain in greater detail how both allocated and unallocated contingency are calculated and how those calculations contribute to the current revenue request.

A. Allocated contingency is identified based on project specific risks. The potential cost impact if that risk were to come to fruition is estimated and the probability of the risk coming to fruition is assessed. The cost impact times the probability provides the earned monetary value. This project risk is associated with a schedule activity to capture when

the risk may come to fruition. The earned monetary value is then forecast in a month-year based on the selected schedule activity.

Unallocated contingency on a project basis is calculated based on the maturity of the estimate basis. A class 3 estimate based on a mature drawing set will typically include a 10% unallocated contingency to account for general estimate uncertainty. In order to forecast how much of the project based unallocated contingency is required in a given calendar year, the company associates the project unallocated contingency on the finish date of two schedule activities – main install and restoration. These two activities are used as they represent activities that notably contribute to estimate uncertainty. With the project unallocated contingency associated with schedule dates, then the project based unallocated contingency amounts are spread over time and summed to an annual dollar amount.

Finally, a review of the project unallocated contingency amounts for a given year and programmatic risks and/or uncertainty for that time period can contribute to a programmatic unallocated contingency amount. *See* NSG-PGL Ex. 31.5 (PGL's response to AG data request AG 9.05). .

Q. The AG Panel expresses concern that there is no fixed cap on contingency disbursement to individual projects, and questions the accountability and traceability of contingency usage. AG Ex. 4.00 at 47. How do you respond?

A. The PRP's tiered governance structure provides accountability through a three-level approval process for contingency drawdowns. Project-level contingency drawdowns require documentation of the triggering risk event and approval by the project manager.

Allocated contingency releases require PMO-level review confirming that the identified risk has materialized. Portfolio-level contingency releases require executive-level authorization with documentation of the specific project need and the basis for the disbursement. *See* NSG-PGL Ex. 17.0 at 73–74; NSG-PGL Ex. 27.1.

The absence of a fixed percentage cap does not mean contingency is uncontrolled. Rather, it means the Company has focused on proper governance and controls while it retains the operational flexibility to respond to project-specific risks that vary in magnitude depending on the nature and location of each project. A rigid cap would force the Company to either over-allocate contingency to low-risk projects or under-allocate to high-risk projects—neither of which produces a more reasonable result than the risk-based methodology the Company employs.

All contingency disbursements are tracked, documented, and subject to reconciliation in future rate proceedings. The Company's project controls system maintains a complete audit trail of every contingency release, including the triggering event, the amount disbursed, the approving authority, and the project to which it was applied. This information is available for review in future proceedings where the Commission will determine whether actual costs were prudently incurred. NSG-PGL Ex. 17.0 at 28–30.

Q. The AG Panel identifies what it characterizes as contradictory contingency figures for 2026—citing $38.9 million, $22.8 million, $23.9 million, and $28.5 million—and asserts that PGL's "rebuttal testimony and supporting documents demonstrably contradict each other." AG Ex. 4.00 at 45–48. Does the AG Panel's comparison table accurately present figures that PGL provided?

A. No. This is the central problem with the AG Panel's presentation, and it is important to be precise about it.

The AG Panel's table at page 44 of AG Ex. 4.00 is introduced as showing "the variations in the PRP contingencies PGL has identified" (*id.*). But the figures in that table are, according to the AG Panel's own footnotes, values the AG Panel itself derived by extracting and summing data from the Company's exhibits—not figures the Company presented as its contingency request. Footnote 86 states the base figure is the "Sum of" an exhibit's project list; footnote 87 is a "Sum of" contingency values; footnotes 92 through 95 are the AG Panel's own formulas ("= Ex. 17.1 Base + …"). Whatever the intent, the effect of presenting AG-derived values under the heading of variations "PGL has identified" is to attribute to the Company an inconsistency that is a product of the AG Panel's own derivation methodology.

Q. What is the specific error in how the AG Panel derived these figures?

A. The AG Panel sorted projects by their in-service year and summed the associated costs and contingency for projects showing a 2026 in-service date. That is not how the 2027 test-year request is constructed. Program cost for a given year is based on the cash flow occurring in that year, not on which year a project is placed in service. A project that

incurs cost in 2026 but is not placed in service until 2027 contributes its 2026 cash flow—including the portion of contingency assigned to 2026—to the 2026 program cost. By sorting on in-service year, the AG Panel systematically excluded 2026 cash flow belonging to projects with 2027 in-service dates. The AG Panel's own footnote acknowledges a symptom of this: its "Source 1" figure, it notes, "includes one 2025 project"—an artifact of sorting on a date field that does not align with how the program is budgeted.

Q. Are there additional errors in the AG Panel'' table beyond the in-service sorting?

A. Yes, there are three. First, the AG Panel's "Source 3" figure of $22,775,973 is taken from a single WBS element and understates contingency even as of the January 5, 2026 filing. Contingency in that filing is carried in two WBS elements, not one: Q-3516-150005 (Contingency) and Q-3516-150004 (Opportunities & Risks, $3,516,568). Presenting one element as though it were total contingency is itself an incomplete representation. Second, the AG Panel's "Source 4" figure of $28,477,730 is drawn from Appendix A of the CSPP and represents only unallocated contingency at a 3/30/26 data date; it excludes allocated contingency and therefore is not a total-contingency figure at all. Third, the AG Panel's "Total PRP—Source 3" combines figures drawn from two different data dates—a contingency figure from a 9/1/25 basis with a base-cost figure the AG Panel derived from a 3/30/26 basis—producing a total that corresponds to no actual point-in-time program plan.

Q. Does the AG Panel's own table contain internal inconsistencies?

A. Yes. The AG Panel's footnote 92 states that "Total PRP — Source 1" of $210,000,000 equals its base figure plus its "Source 1" contingency. But those two figures ($170,575,061 and $23,878,432) sum to $194,453,493—which is the amount on the AG Panel's own "Total PRP — Source 2" row, not the $210,000,000 the footnote attaches them to. Correspondingly, footnote 93''s combination sums to $209,475,061, which approximates the "Source 1" row rather than the "Source 2" row to which it is attached. The AG Panel's own narrative gets the pairing right, which indicates the table's footnotes are transposed. This is noted not to belabor a labeling error, but because a table offered as proof that the Company's figures do not reconcile does not itself internally reconcile.

Q. Separately from the page-44 table you have been discussing, the AG Panel also points to data in the native file of NSG-PGL Ex. 17.3 that it describes as "hidden," stating that once unhidden it reveals several problems with how Peoples Gas calculated its PRP costs. *Id.*, at 23–24. How do you respond?

A. The AG Panel's characterization gives the wrong impression, and it is worth explaining plainly what the referenced material actually is. The tab the AG Panel unhid—labeled "Sheet3"—is a working-level comparison worksheet that had no input into the values displayed in NSG-PGL Ex. 17.3. It reflects the superseded September 1, 2025 program data, in which contingency was spread across individual projects, including the legacy placeholder projects, before the Company's re-baseline. During the development of the exhibit, that worksheet was used to compare against the September 1, 2025 view; once the exhibit was revised to present historical actuals together with the March 30, 2026 re-

baselined budget, the September 1, 2025 comparison worksheet was no longer relevant to the exercise and was hidden for that reason. Nothing was withheld: the worksheet reflects an earlier data date the Company had already moved past, and it fed none of the numbers shown in the exhibit.

Understood in that light, each of the three items the AG Panel identifies resolves to the same explanation. The placeholder projects the AG Panel sees are present because Sheet3 is the September 1, 2025 view, which predates the removal of those projects—not because they remain in the Company's current plan. The contingency "spread by project" that the AG Panel examines is likewise the September 1, 2025 allocation, the same superseded data date from which the AG Panel elsewhere draws the $22,775,973 contingency figure it relies upon. In other words, the AG Panel's "hidden data" findings are properties of the original baseline the program has already moved off of; they do not describe the current, re-baselined request.

On the AG Panel's specific point that 2026 costs reflect a partial year, that is correct and expected, and it is not an incompleteness in the data. The PRP's scheduled construction start was March 2026. There were no plans to begin earlier, given winter conditions and the timing of the program's resumption. A 2026 view that begins in March therefore reflects the program's planned construction calendar—it is a complete picture of a program that was planned to start in March, not a truncated picture of a program that starts in January.

Finally, the AG Panel observes that the backup calculations on the September 1, 2025 worksheet sum to approximately $15.5 million less than the contingency the Company identifies in rebuttal. That difference reflects the distinction between

contingency allocated to individual projects at the superseded September 1, 2025 baseline and the program's total contingency—a difference inherent in that earlier, project-level view. The Company does not ask the Commission to reconcile the superseded September 1, 2025 worksheet against its current request, because that earlier view has been superseded in its entirety. As set out in NSG-PGL Ex. 31.1, the Company's updated request is presented at a single baseline, with all contingency—allocated, unallocated, and program-level—itemized in one place. That updated presentation, not a hidden comparison worksheet reflecting an abandoned data date, is the basis on which the Company's contingency should be evaluated.

Q. Turning to the disallowance amounts, does the AG Panel's approach result in any double counting?

A. Yes. The AG Panel's cost-per-mile disallowance and its separate contingency disallowance, if both adopted, remove the same contingency twice. The AG Panel builds a cost-per-retirement-mile figure using a program cost of approximately $188 million, which excludes contingency, and then applies that cost-per-retirement-mile figure against a program cost of $210 million, which includes contingency. The resulting $97.2 million disallowance therefore already sweeps in the program's contingency. When the AG Panel then adds a separate, additive recommendation to disallow the standalone contingency WBS element—$71.06 million for 2026 and 2027—it disallows that contingency a second time. And although the AG Panel characterizes its recommendation as a reduction of contingency, the combined effect is not to adjust contingency but to remove it

entirely—which is inconsistent with the AG Panel's own stated position that it does not contest the use of contingency as part of cost investments in principle. AG Ex. 4.00 at 35.

Notably, when the Company asked the AG Panel directly, through NSG-PGL-AG 5.08, to identify any workpaper or analysis confirming that no dollar of PRP investment is disallowed under both the cost-estimate reduction and the contingency elimination, the Panel identified none, instead reiterating only that "the record does not clearly reconcile the relationship between project-level contingency, portfolio-level contingency, allocated contingency, unallocated contingency, and the total contingency amount included in PGL's request." AG Ex. 4.00 at 48:829–831; NSG-PGL Ex. 31.5 (AG response to Companies data request NSG-PGL-AG 5.08(b)-(c)). The absence of any such analysis confirms that the Panel has not accounted for—and cannot rule out—the double counting described above.

Q. Is the $188 million figure the AG Panel uses as Peoples Gas's original request accurate?

A. No. The Company's original forecast, as stated in NSG-PGL Ex. 1.0, was approximately $214 million for 2026 and $360 million for 2027—the total PRP funding envelope. The $188 million figure represents 2026 project costs excluding contingency. It is derived by taking the $214 million total and subtracting the two contingency-related WBS elements—Opportunities & Risks ($3,516,568) and Contingency ($22,775,973). By presenting the contingency-excluded $188 million figure as though it were the Company's total original request, the AG Panel understates the Company's 2026 PRP

forecast and then treats the difference as evidence of an unexplained cost increase. That same error underlies the AG Panel's recommended $97.2 million disallowance.

Q. How should the Commission read the range of contingency figures the AG Panel highlights?

A. The apparent range resolves into two categories, neither of which supports a disallowance. Much of it is attributable to the AG Panel deriving figures through the in-service sorting and single-data-date errors described, and then presenting those AG-derived figures as though the Company had offered them as competing versions of its request. The remainder reflects legitimate estimate maturation over the evidentiary period—the ordinary refinement of a multi-year program's estimates as designs advance and the program plan matures. Neither category reflects an inconsistency in the Company's actual request, which—as presented in this surrebuttal at a single forecast—is stated once and fully itemized.

Q. Does Peoples Gas acknowledge any shortcoming in how it presented contingency information in this proceeding?

A. Yes, and the Company wants to be candid with the Commission about it. As Peoples Gas's PRP contingency framework evolved from initial program planning through subsequent revisions, the terminology and presentation used to describe contingency evolved as well—and, at times, were presented differently across exhibits and filing rounds. The CSPP, for example, presented unallocated contingency as a stand-alone line while including allocated contingency within an annual subtotal—a presentation that

differs from how the Company disaggregated contingency elsewhere and that does not, on its own, clearly convey total contingency.

The Company acknowledges that this variation in terminology and presentation—rather than any difference in the underlying costs, the reasonableness of the contingency methodology, or the governance controls applied to contingency funds—accounts for a meaningful portion of the apparent misunderstanding identified in this proceeding. The updated, forecast request presented in this surrebuttal is intended to resolve that presentation issue directly, by stating the Company's request once, with every dollar clearly categorized and summarized.

Q. Why should the Commission reject the AG Panel's proposed contingency disallowance?

A. The Panel's proposal is inconsistent with both the purpose of contingency and the record evidence.

Contingency exists to address uncertainty and is industry practice, and the early years of a large-scale infrastructure program are precisely when uncertainty is greatest. Eliminating contingency during the most capital-intensive phase of PRP execution would underfund identified project risks and increase the likelihood of funding shortfalls in a safety-driven, Commission-directed program. *See* NSG-PGL Ex. 17.0 at 53.

Moreover, the record demonstrates that the Company's contingency framework aligns with industry practice and is functioning exactly as intended. As estimates have matured and execution assumptions have become more refined, total 2026 contingency has declined—an update reflecting the risk-based methodology: as uncertainty decreases

and project risks become better understood, contingency correspondingly declines. For Class 3 estimates, unallocated contingency is established at 10% of base project costs; any contingency exceeding that threshold reflects specific project risks identified, documented, and assigned mitigation strategies through the Company's risk-management process. Those risks are identified in the applicable risk registers and discussed project-by-project in NSG-PGL Ex. 17.1. *See id.*, at 54.

Importantly, FTI independently reviewed all 81 PARs produced in this proceeding and confirmed that the Company is not double-counting contingency costs. Indeed, FTI identified only a single data-entry discrepancy, which did not result in any duplicative recovery. *See* NSG-PGL Ex. 27.0 at 9–14; NSG-PGL Ex. 27.7.

The AG Panel also fails to recognize the distinct roles of project-level and program-level contingency. Project-level contingency addresses uncertainty within individual projects. Program-level contingency provides portfolio-wide flexibility to manage how those risks ultimately materialize across the broader PRP during execution. As FTI explained, this two-tiered structure is consistent with AACE International guidance for large-scale infrastructure programs and represents a reasonable and widely accepted approach to contingency management.

Most importantly, customers ultimately pay only prudently incurred costs. Contingency is a forecasting and planning tool, not a guarantee of recovery. To the extent identified risks do not materialize and project costs are lower than forecast, customers will not permanently bear costs that were never incurred. *See* NSG-PGL Ex. 29.0. The AG Panel seeks to eliminate contingency at the front end of the planning process even though existing ratemaking mechanisms already protect customers while allowing the

Company to plan for known execution risks. Accordingly, the Panel's proposed disallowance should be rejected.

VI. FEASIBILITY OF THE 2035 RETIREMENT DEADLINE AND INTERMINGLED PIPE

Q. The AG Panel concludes that the PRP is "unlikely" to retire all CI/DI main under 36 inches by 2035, citing PGL's historic pace of approximately 45 miles per year, the roughly 4 miles retired in 2025, and the magnitude of the remaining workload. *See* AG Ex. 2.00 at 11; AG Ex. 4.00 at 49. How do you respond?

A. The Panel's conclusion is based on a fundamentally flawed premise: that historical SMP performance is predictive of future PRP performance. It is not. The legacy SMP addressed all CI/DI pipe regardless of diameter, included high-pressure conversion activities, and operated under significantly different policy objectives, funding mechanisms, and governance structures. The PRP is a focused, Commission-directed program with a single objective—retiring all CI/DI main under 36 inches by 2035—supported by strategic alliance contracting, a phased workforce ramp-up, and the CSPP's annual retirement targets. The Panel's 2049 projection is the product of a model that extrapolates historical performance while deliberately disregarding the Company's robust and thoughtful planned execution ramp-up—a model the Panel itself admitted is "built on historic data" and was not adjusted to reflect the Company's planned construction increase. NSG-PGL Ex. 17.19 (AG Response to NSG-PGL-AG 1.11). A feasibility analysis that intentionally excludes the Company's actual execution plan is not a reliable

or credible basis for evaluating whether the Commission's 2035 directive can be achieved.

Nor is the revised 2026 target of approximately 14 retirement miles evidence that Peoples Gas cannot meet the 2035 directive. The 2026 plan reflects a startup year in which the Company is simultaneously mobilizing contractors, onboarding an initial field workforce of approximately 70 resources, establishing construction protocols, refining execution processes, and building the operational infrastructure necessary to support long-term program acceleration and success. A real concern is the availability of skilled labor to safely perform the required work necessary to meet the Commission's directive. The constrained 2026 workforce availability is further impacted by competition from data centers, which are paying premiums for skilled construction labor. As a result, 2026 throughput is not representative of the program's anticipated steady-state production capability, as the Company is actively continuing to expand its available resources.

This same labor-market dynamic—premium wages required to retain and attract skilled construction workers in a competitive market—also directly explains a portion of the elevated per-project costs reflected in the 2026 PRP plan. The 2026 PRP must secure and retain field labor at rates sufficient to compete with data-center and other major infrastructure projects bidding for the same pool of skilled workers. That cost pressure is real, documented, and entirely external to any PGL management decision. It further confirms that the Panel's historical SMP benchmark—which does not reflect current labor-market conditions—is not an appropriate measure of the prudence of 2026 PRP costs.

The Company's forecast reflects that expected ramp-up. The Company's 2027 investment level, endorsed by the PRP ESC on July 13, 2026, is approximately $349 million (with $320 million in service) (NSG-PGL Ex. 31.3), which incorporates labor premiums necessary to attract additional outside workers and reflects more than double the 2026 investment level. That investment is expected to result in a substantial increase in annual retirement mileage—targeting approximately 47 miles of CI/DI retirement—as the workforce expands and productivity improves. The Company's 2028 and 2029 forecasts of approximately $532 million and $537 million, respectively, reflect further acceleration toward the sustained production levels necessary to achieve the Commission's 2035 directive.

Q. The AG Panel also cites PGL's 2009 commitment to complete CI/DI retirement by 2030, arguing that PGL's history of missed targets undermines the credibility of the current 2035 timeline. AG Ex. 4.00 at 50–51. How do you respond?

A. The 2009 filing reflects PGL's assessment under a fundamentally different program architecture, governance structure, and cost-recovery mechanism—one that preceded the SMP pause, the QIP rider, the Commission's 2024 SMP Investigation Order, and the PRP itself. The circumstances that prevented achievement of earlier targets—the Commission-ordered SMP pause, evolving regulatory requirements, workforce availability constraints, and the absence of dedicated program management infrastructure—are precisely the conditions the PRP was designed to address. The PRP's structural safeguards—secured contractor capacity through strategic alliance agreements, a phased execution model with annual CSPP targets, dedicated PMO oversight, and risk-based project prioritization—did

not exist under any prior program iteration. These are not aspirational commitments; they are contractual and organizational structures already in place. The strategic alliance agreements provide contractually committed field resources that PGL did not have under the SMP.

The Panel cannot simultaneously criticize PGL for failing under prior program structures and then argue that the Commission-directed reforms addressing those failures are merely "another revision." The PRP exists because the Commission determined a fundamentally different approach was necessary, and the Company has implemented that approach.

Q. In its direct testimony, the AG Panel asserted that including LP-to-MP pressure upgrades and retiring "intermingled" non-CI/DI pipe (approximately 16% of PRP scope) adjusts the effective rate of CI/DI retirement and increases costs. AG Ex. 2.00 at 51–53. Does the AG Panel maintain this critique in rebuttal?

A. Not in any meaningful way. In rebuttal, the Panel substantially narrows its criticism and effectively acknowledges several points that support PGL's position. Most notably, the Panel admits that replacing intermingled pipe often "makes good engineering sense" and acknowledges that, where an LP-to-MP upgrade is being performed, "there is no option and it must all be replaced or inserted if it is to remain in service." AG Ex. 4.00 at 54.

Those admissions are significant because they confirm that retirement of intermingled pipe is not optional work that diverts resources from CI/DI retirement. Rather, it affirms that it is often an operationally necessary component of safely and efficiently retiring CI/DI facilities. As the Panel itself recognizes, gas utilities cannot

simply retire a CI/DI segment while leaving incompatible or isolated intervening facilities in service where system design, pressure requirements, or operational considerations require those facilities to be addressed concurrently. *Id.*

The Panel's remaining criticism appears to be that replacing intermingled non-CI/DI facilities increases the amount of work performed relative to the number of CI/DI miles retired. While that observation may be true in a purely arithmetic sense, it does not establish that the associated work is unnecessary, imprudent, or outside the scope of the PRP. To the contrary, the Panel expressly acknowledges that replacement of certain intermingled segments may be the most logical and efficient engineering solution and that LP-to-MP upgrades necessarily require replacement of intervening facilities if they are to remain in service. *Id.*

Accordingly, the relevant question is not whether retirement of intermingled pipe increases the amount of work performed. The relevant question is whether that work is reasonably required to enable the safe, reliable, and cost-effective retirement of CI/DI infrastructure. The record demonstrates that it is.

Similarly, the Panel's discussion of LP-to-MP upgrades does not undermine the PRP. The Panel acknowledges that pressure upgrades can require additional replacement activity and expressly states that, "in the case of a simultaneous pressure upgrade," replacement of intermingled facilities is appropriate. *Id.* Peoples Gas agrees. However, LP-to-MP upgrades are not being undertaken as a standalone program objective or as a means of expanding PRP scope. Rather, they are implemented on a targeted, project-specific basis where engineering analysis demonstrates that the upgrade is necessary to

facilitate the retirement of legacy facilities and improve long-term system performance. *See* NSG-PGL Ex. 17.0 at 86–88.

Ultimately, the Panel's rebuttal confirms that the dispute is not whether intermingled pipe replacement and certain LP-to-MP upgrades are operationally necessary. The Panel expressly acknowledges that they often are. The dispute is simply whether that enabling work should be viewed as reducing the efficiency of the PRP. It should not. The Commission's objective is the safe and prudent retirement of CI/DI infrastructure, and work that is necessary to accomplish that objective is properly considered part of the retirement effort rather than a distraction from it.

Q. The Panel makes a somewhat related recommendation that the Commission direct PGL to explicitly separate all proposed system improvement ("SI") work that relates to projects outside of the PRP in this and future cases. AG Ex. 4.00 at 49. Staff witness Mr. Seagle makes the same recommendation. Staff Ex. 13.0 at 7. How do you respond?

A. The Company does not object to presenting SI work separately in future filings for transparency purposes, and will do so beginning with Phase II reporting. However, treating SI work as outside the PRP for purposes of cost recovery would be inappropriate where that work is operationally necessary to enable CI/DI retirement—for example, where an LP-to-MP upgrade is required to safely decommission a downstream CI/DI segment. The Company will clearly identify which SI work is an integral enabling component of CI/DI retirement and which is independent.

VII. PRP PROJECT DOCUMENTATION AND THE FORMER 2027 PLACEHOLDER PROJECTS

Q. Staff witness Mr. Seagle initially expressed concern that the generic "PRP New Project" placeholder entries lacked sufficient documentation for a prudence determination, and recommended that the Company provide detailed documentation and explain how those projects would be completed by the end of 2027. *See* Staff Ex. 4.0 at 22. Does Mr. Seagle maintain his stated concern?

A. No. Staff's concern has been fully resolved. On rebuttal, Mr. Seagle confirms that he "has no further concerns" regarding the former placeholder projects in light of the documentation the Company provided in NSG-PGL Ex. 3.17 REV and Ex. 17.2. Staff Ex. 13.0 at 2–3. Accordingly, Mr. Seagle has withdrawn his direct-testimony recommendation and now proposes no PRP capital cost disallowance. *Id.*

Moreover, as we noted above, Mr. Seagle expressly rejects the AG Panel's large PRP cost-estimate disallowances, finding PGL's estimates reasonable. Staff Ex. 13.0 at 6. Staff's review of the same approximately 6,500 pages of documentation—construction drawings, competitively bid cost estimates, Class 3 PAR estimates, and approval materials for each Phase I project—that the AG Panel criticizes as insufficient led to the opposite conclusion, underscoring the unreasonableness of the Panel's blanket disallowance recommendation.

Q. The AG Panel also criticizes the timing of PGL's document production, noting that PGL provided PARs on April 17, 2026 and June 3, 2026, comprising nearly 6,500 pages, and characterizing the production as late. *See* AG Ex. 4.00 at 27. The Panel suggests that PGL's explanation—that the timing reflects enhanced transparency efforts under the PRP framework rather than a lack of evidentiary support or internal controls—is insufficient. How do you respond?

A. The Panel's criticism is internally contradictory. The Panel cannot simultaneously maintain that PGL's cost estimates are unsupported and unreasonable while also objecting to the Company's production of nearly 6,500 pages of project-level documentation as excessive or untimely. The very documentation the Panel characterizes as burdensome—detailed PARs, construction drawings, competitively bid contractor cost estimates, Class 3 estimates, risk registers, and approval materials for each Phase I project—is precisely the transparent, project-specific evidence that demonstrates the reasonableness of PGL's proposed investments. If the Panel's position is that PGL's costs lack evidentiary support, then the production of comprehensive project-level documentation should resolve that concern, not compound it. That Staff reviewed the same documentation and expressly found PGL's estimates reasonable confirms that the materials serve their intended purpose.

Moreover, the timing of PGL's production reflects the realities of a large-scale capital program in active development and ramp-up, not a failure of internal controls. The PARs produced in April and June 2026 incorporated current 2025–2026 contractor pricing from the competitive bid process that concluded in 2025, Class 3 engineering estimates that were finalized as projects progressed through detailed design, and risk

registers that were populated as project-specific constructability assessments were completed through activities like physical walkdowns and coordination with other underground entities which cannot occur earlier in the project lifecycle. These materials could not have been produced earlier because the underlying information did not exist in final form until those dates. The Company explained this timing in its supplemental direct testimony, and Staff accepted that explanation without reservation.

The Panel's attempt to recharacterize normal program maturation as a procedural deficiency ignores both the purpose of the rate case discovery process and the realities of utility construction planning. For major infrastructure programs such as the PRP, project scopes, execution assumptions, and cost estimates are expected to evolve as engineering progresses and actual field-performance data becomes available. The discovery process exists precisely so that this more refined information can be provided to parties and incorporated into the evidentiary record as it develops. The Panel's criticism is therefore inconsistent with both the practical lifecycle of construction projects and the Panel's own acknowledgment that it "understand[s] [the PARs] to be a summary of internal documentation consistent with the goals of the documentation and transparency process improvements." AG Ex. 2.00 at 28.

Q. In light of the developments discussed above, are the Company and Staff now aligned on PRP project documentation?

A. Yes, and this alignment is significant. The record demonstrates that Peoples Gas has not treated its documentation practices as static. Rather, the Company has continually refined and supplemented its PRP project support throughout this proceeding in response to

stakeholder feedback, evolving project information, and Staff's transparency objectives. Those efforts have achieved their intended purpose. After reviewing the updated project documentation, cost support, and planning assumptions, Mr. Seagle confirmed that he has "no further concerns" regarding the former placeholder projects and expressly rejected the AG Panel's recommended cost-estimate disallowances. Staff Ex. 13.0 at 3, 6. Staff's conclusion—reached after reviewing the same project documentation the AG Panel criticizes as insufficient—underscores the unreasonableness of the Panel's blanket disallowance recommendation.

VIII. REPAIR AND REHABILITATION TECHNOLOGIES, CIPL, AND RATEPAYER IMPACTS

Q. PIRG witness Mr. Lewnard disagrees with PGL that it comprehensively considered repair and rehabilitation techniques, such as CIPL, as part of its project-level alternatives analysis. PIRG Ex. 8.0 at 7. How do you respond?

A. The Company distinguishes among options based on constructability, operational feasibility, outage implications, scalability, and consistency with the Commission's directive to systematically retire—not repair or rehabilitate—more than 1,000 miles of CI/DI main. The Commission has consistently distinguished retirement from repair or rehabilitation: repair or rehabilitation leaves CI/DI pipe in service as an operating asset, with continued reliance on decades-old host material, whereas retirement provides a clear, verifiable endpoint necessary for compliance tracking. Where a technology such as CIPL does not satisfy the retirement directive or does not provide long-term risk reduction comparable to replacement, the Company has reasonably concluded that

replacement is appropriate. That said, as discussed in Section II, Peoples Gas joins PIRG's call for Commission direction on how pipe repair and rehabilitation alternatives may fit within the retirement directive; the regulatory uncertainty on that threshold question—not categorical opposition—constrains deployment of these technologies in the PRP.

Q. Mr. Lewnard and Dr. deLeon note that, although the Company lists CIPL as an alternative in its supplemental PARs, it never calculated CIPL's cost—preventing a true cost comparison. Is the Company's alternatives analysis adequate?

A. We believe the alternatives analysis is adequate when viewed in the context of the decision it was intended to inform. Each PRP supplemental PAR evaluates multiple potential approaches, including CIPL, and documents the reasons the Company did not select CIPL as the preferred project alternative. As the Company explained in discovery responses such as PIRG 6.11 and 6.12, CIPL was screened out during the alternatives evaluation because of significant constructability constraints, extended-outage considerations, continued reliance on the aging host pipe, and the unresolved regulatory question whether CIPL satisfies the Commission's CI/DI retirement directive. Because CIPL was not identified as a viable preferred alternative for implementation under those circumstances, Peoples Gas did not advance it to the detailed engineering and estimating stage required to develop a project-specific construction cost estimate.

We acknowledge that the PARs therefore do not contain developed CIPL cost estimates. However, that does not mean CIPL was ignored or excluded from consideration. Rather, the Company evaluated CIPL as part of its alternatives review,

concluded that it was not the appropriate project solution given the circumstances presented, and accordingly focused its detailed design and cost-estimating efforts on the alternative selected for execution. Utilities routinely allocate finite engineering and estimating resources to alternatives that remain viable candidates for implementation, not to alternatives that have already been eliminated through the planning process. Requiring a utility to develop fully engineered cost estimates for every alternative considered—regardless of whether it remains a realistic option—would impose unnecessary costs and divert resources from advancing the projects needed to satisfy system reliability, safety, and operational objectives within required planning and construction timelines.

To the extent the Commission clarifies that CIPL may be used to satisfy the retirement directive, Peoples Gas would incorporate that guidance into future project evaluations and develop project-specific CIPL cost estimates where appropriate. That approach would provide the Commission and stakeholders with the benefit of a clear regulatory framework while avoiding the need to revisit and re-estimate an entire portfolio of projects that were developed under a different understanding of the retirement requirement.

Q. PIRG witness Mr. Lewnard asserts that CIPL could achieve cost savings of approximately 30 to 60 percent per foot relative to traditional pipe replacement. PIRG Ex. 8.0 at 33. Is that cost analysis reliable?

A. No. Mr. Lewnard's cost-savings estimate is incomplete and misleading. It relies on vendor estimates from Progressive Pipe Management ("PPM") that exclude critical costs the Company would actually incur to implement CIPL, including excavation pits,

restoration, service reconnection, and project management. *See* NSG-PGL Ex. 15.0 at 28. In addition, PRP replacement includes retirement of all services associated with a main—often dozens of services per project—an obligation that Mr. Lewnard's CIPL cost comparison does not address. *Id.* Moreover, CIPL is not currently commercially available in the United States for the smaller-diameter 4-inch and 6-inch pipe that comprises much of Peoples Gas's system, and Mr. Lewnard dramatically underestimates the customer outage time CIPL requires, which is properly measured in weeks, not days, given the need to temporarily disconnect and reconnect every customer served by an affected main segment. *Id.* For these reasons, Mr. Lewnard's 30-to-60% per-foot cost-savings estimate does not provide a reliable basis for evaluating CIPL as an alternative to replacement.

Q. Is CIPL an NPA within the meaning of the NPA framework the Company is developing with Charles River Associates ("CRA")?

A. No. CIPL is not an NPA; it is a pipe repair and rehabilitation technology—a different means of addressing the same pipe, not an alternative to addressing it. CRA's NPA framework is limited to permanent alternatives that eliminate the need to replace CI/DI gas mains altogether, principally electrification and utility thermal energy networks, and it expressly excludes repair and rehabilitation technologies, such as CIPL, that do not eliminate the need for natural gas service to the affected customers. *See* NSG-PGL Ex. 26.0 at 11–14, 23–24. The Company will continue to evaluate repair and rehabilitation technologies, including CIPL, for Phase II and future projects where they are technically and economically feasible, consistent with the project-specific framework described above.

Q. PIRG witness Dr. deLeon presents an "illustrative" scenario in which PGL relines CI/DI pipe greater than 8 inches in diameter instead of replacing it, and asserts that this would produce materially lower ratepayer costs. PIRG Ex. 6.0 at 2. How do you respond?

A. Dr. deLeon's analysis rests on flawed assumptions, incomplete cost inputs, and an unresolved regulatory premise. Her illustrative relining scenario relies on generic vendor cost estimates drawn from publicly available sources, assumes that continued reliance on relining would satisfy the Commission's directive to retire CI/DI facilities, and omits substantial costs that Peoples Gas would actually incur to implement such a program. As a result, her comparison significantly understates the cost of relining and overstates its purported benefits.

The deficiencies in Dr. deLeon's analysis are not merely theoretical. In discovery, PIRG confirmed that her PPM cost figures are based on publicly available vendor information rather than project-specific estimates developed for Peoples Gas's system or the unique conditions associated with replacing cast iron pipe in a dense urban environment. NSG-PGL Ex. 31.7. She further acknowledged that her CIPL cost assumptions exclude numerous cost categories that Peoples Gas would incur, including street restoration, City of Chicago permitting fees, traffic control, LP to MP conversion costs, service line testing and replacement, meter set upgrades, and appliance relighting. *Id.*

Notably, Dr. deLeon modified her model on rebuttal to incorporate customer disconnection, reconnection, and relighting costs—an acknowledgment that her direct-testimony analysis was incomplete. Even with those revisions, however, she continues to

omit significant project cost elements and relies on generic vendor data rather than utility or project-specific estimates. Her revised analysis adjusts the claimed savings from approximately 17% to a range of 11% to 15%, demonstrating how sensitive her conclusions are to the inclusion of additional cost elements, which are required of the Company. Once the full range of costs associated with implementing a large-scale relining program is considered, those purported savings would be expected to shrink further and could disappear entirely.

Moreover, the alleged savings must be viewed in context. Dr. deLeon estimates a difference of approximately $400 million in undepreciated plant between full replacement and her relining scenario as of 2050. Relative to the approximately $4.8 billion to $5.5 billion in cumulative investment contemplated over that period, the difference is comparatively modest. More importantly, it comes at the cost of leaving hundreds of miles of aging CI/DI pipe in service, along with the operational, integrity-management, and safety risks associated with continuing to rely on that infrastructure for decades into the future.

Dr. deLeon's rebuttal testimony advances a new argument regarding stranded-asset risk: that credit agency assessments of PGL's exposure are irrelevant because those agencies "likely find that stranded asset risk does not imperil PGL's credit ratings because they expect the cost of stranded assets to be shouldered by ratepayers." PIRG Ex. 6.0 at 20. She further asserts that the risk is asymmetric—that if demand declines materially, remaining customers will bear stranded costs absent policy intervention. This argument proves too much. Every utility capital investment carries some theoretical risk that future demand conditions may differ from current projections. If the Commission

were to adopt the principle that a utility should defer safety-critical capital investment whenever a hypothetical future demand decline might strand that investment, no large-scale infrastructure program could proceed. The appropriate regulatory response to demand uncertainty is not capital-spending deferral but sound depreciation policy, regulatory mechanisms for addressing potential stranded costs if and when they materialize, and continued monitoring of demand trends—precisely the approach the Commission has taken. Moreover, Dr. deLeon's own updated modeling demonstrates that the difference in undepreciated plant between her two scenarios is approximately $400 million out of a $4.8–$5.5 billion program—a modest incremental exposure that does not justify accepting the safety, reliability, and compliance risks of retaining hundreds of miles of aging CI/DI infrastructure in service.

Ultimately, Dr. deLeon does not ask the Commission to adopt her relining scenario, presenting it only as an illustration. The prudent response to long-term uncertainty regarding future gas demand is not to defer or adjust investment in safety-critical infrastructure based on an illustrative model built on incomplete assumptions. Rather, it is to continue making prudent investments necessary to maintain a safe and reliable system while developing analytical tools—such as the NPA framework discussed in Section X—that can inform future investment decisions as demand trends become clearer.

Q. Can you illustrate how Peoples Gas evaluates whether CIPL is an appropriate alternative in a particular situation?

A. Yes. Although the PRP projects in this case did not present circumstances that favored CIPL over replacement, the Company has developed and applies a structured, project-specific framework for evaluating cured-in-place lining, which we summarize here for the Commission's awareness and present in detail in NSG-PGL Ex. 31.6. The Company recognizes that, where it can be used, CIPL may seal existing leaks, prevents future leaks, eliminates methane emissions, removes internal corrosion and PCBs, and minimizes excavation, traffic congestion, and restoration.

At the same time, the Company evaluates each potential CIPL opportunity against the following factors: (1) customer disruption—because the pipe must be taken out of service to purge, clean, and line it, mains with multiple service taps are not ideal candidates; (2) structural integrity—because the liner is considered non-structural, the existing carrier pipe must remain intact, and pipe with fittings, bends, internal clamps, or taps requires additional work to clean, prepare, or support the liner; (3) cost—each application must be reviewed individually to understand the full project cost; and (4) the fact that the leak-prone pipe remains in service and is not considered "retired," which creates regulatory uncertainty in light of the Commission's retirement mandate. The lining process itself—detailed in NSG-PGL Ex. 31.6—involves pre-cleaning closed-circuit television ("CCTV") inspection to assess surface condition, obstacles, and taps; abrasive blast cleaning to remove corrosion; post-cleaning CCTV inspection to confirm the surface is prepared and waste is removed; adhesive application inside the liner before insertion; liner insertion using pressurized air inversion; post-lining CCTV inspection and

pressure testing; and service reinstatement through reconnection of gas services and final tie-ins.

Q. Can you provide concrete examples of how the Company has applied this framework?

A. Yes. Two recent projects—both outside the PRP, but illustrative of how the Company evaluates CIPL use cases—demonstrate the framework in practice and are presented with supporting detail in NSG-PGL Ex. 31.6.

The first is the Canalport project, which involved approximately 2,000 feet of leak-prone 24-inch cast iron MP main (operating at approximately 22 psi) installed in 1909, with 43 repairs between 2000 and 2020—including 5 internal sealants, 7 external sealants, and 4 band clamps between 2018 and 2020 alone. The location presented multiple challenges: it sits in a dense urban area near the Chicago River, the pipeline crossed under ramps leading to Interstate 90/94, an elementary school is located within the project footprint, and multiple railroad crossings lie to the east. The Company selected lining for this project because the header main could be taken out of service and isolated—making it a feasible candidate for lining in this unique scenario—and lining allowed the Company to maintain the required gas flow through the existing 24-inch main. The total cost of lining was estimated to be approximately 30% lower than a full steel replacement given the extremely complicated nature of construction at that specific site; lining required only four access pits rather than extensive trenching; it reduced traffic disruption near the interstate ramp; and it shortened the overall timeline, reducing

restoration time by approximately four weeks and excavation by approximately two weeks.

The second example is the South Shop project at 23rd and Federal, which involved approximately 850 feet of 30-inch cast iron LP main installed in 1891, with 23 repairs between 1980 and 2025—including 6 internal sealants, 4 external sealants, and 3 band clamps between 2007 and 2025. The project area is near the National Teachers Academy, which has a history of grade 1 and grade 2 leaks in the area of the school, has expressed frustration with the Company's return trips for leak repairs, and has limited daytime working hours during the school year. Here, the Company compared a liner option—retiring approximately 925 feet of 30-inch cast iron LP main, lining approximately 850 feet and reinstating it, and installing approximately 75 feet of 16-to-30-inch steel LP main, at a cost of approximately $3.318 million—against an insertion option—retiring approximately 925 feet of the cast iron main, installing approximately 850 feet of 18-inch plastic LP main, and installing approximately 75 feet of steel LP main, at a cost of approximately $3.155 million.

As detailed in NSG-PGL Ex. 31.6, the Company selected insertion as the preferred option because it installs new, non-leak-prone polyethylene main, has the same temperature dependencies as the existing 30-inch cast iron, allows quicker installation and therefore less downtime for the school, and costs less. By contrast, the liner option would have required verifying that the existing cast iron is in good structural condition, additional contractor coordination and outside labor agreements, a longer main outage to allow the epoxy to cure, and a higher cost for no added pipe or system benefit.

Q. What do these examples demonstrate about the Company's treatment of CIPL?

A. They demonstrate that the Company does not categorically reject CIPL, contrary to the criticisms of PIRG witnesses. As the summary slide of NSG-PGL Ex. 31.6 concludes, in rare circumstances a cured-in-place liner may be a feasible alternative to pipe replacement, and the Company evaluates that possibility on a project-specific basis. As Canalport shows, where the critical factors align—an isolatable main, limited service taps, severe construction constraints, and favorable cost and schedule outcomes—the Company will select lining. As South Shop shows, where those factors do not align, replacement or insertion remains the more prudent choice. The same critical factors that limit the widespread feasibility of CIPL—customer disruption, the non-structural nature of the liner, the difficulty of achieving long-term adhesion on pipe with fittings, bends, internal clamps, and taps, cost, and the fact that lined leak-prone pipe remains in service and is not considered retired—are precisely the considerations the Company has identified throughout this proceeding and in its discovery responses.

NSG-PGL Ex. 31.6 presents this evaluation framework in a format that allows the Commission to see how these factors are weighed in practice. These examples reinforce, rather than undercut, the reasonableness of the Company's project-specific approach and its request that the Commission clarify whether CIPL can satisfy the retirement directive.

Q. Mr. Lewnard asserts in rebuttal that CIPL meeting the ASTM F3777-25 standard rehabilitates CI/DI pipe with a service life of 50 years or greater and therefore satisfies the Commission's retirement directive, citing PHMSA's participation in developing that standard. How do you respond to this new argument?

A. ASTM F3777-25 is a recently adopted consensus standard addressing the testing and installation of CIPL for gas distribution mains. The Company does not dispute that PHMSA participated in the development of that standard or that it represents progress in establishing performance criteria for CIPL technology. However, the existence of a testing standard does not resolve the regulatory question before this Commission.

The Commission's directive requires retirement of CI/DI pipe—not rehabilitation. Whether a lined pipe constitutes a "retired" asset for purposes of complying with that directive is a legal and regulatory determination that ASTM F3777-25 does not address. The standard establishes performance criteria for the liner itself; it does not determine whether the host CI/DI pipe remains a regulated distribution asset, whether it remains subject to integrity management requirements, or how it should be classified for compliance-tracking purposes. Indeed, PHMSA's own "Reconditioned Cast Iron" reporting category, created through the 2015 revisions to the Distribution Integrity Management Program ("DIMP") regulations, recognizes rehabilitated cast iron as a distinct asset category rather than retired pipe. Until the Commission determines that CIPL deployment satisfies the retirement directive, Peoples Gas cannot deploy CIPL within the PRP and credit that deployment toward the Commission's 2035 compliance target. This is precisely the clarification requested by both Peoples Gas and PIRG.

Moreover, Dr. Lewnard's proposal would require Peoples Gas to undertake an unprecedented deployment of the technology. In response to data requests, Dr. Lewnard was unable to identify any gas distribution utility in the United States that has deployed ASTM F3777-25-compliant CIPL on more than 10 miles of pipe. NSG-PGL Ex. 31.7 (PIRG response to Companies data request NSG-PGL-PIRG 4.18). Yet he proposes that Peoples Gas substantially alter the PRP's proven replacement strategy in favor of widespread deployment of that technology across one of the nation's largest and most complex urban gas distribution systems. Thus, even if ASTM F3777-25 demonstrates that CIPL can be installed safely and effectively, it does not establish that utility-scale deployment has been demonstrated in circumstances comparable to Peoples Gas' system, nor does it resolve the threshold question of whether such deployment would satisfy the Commission's retirement directive.[2]

Accordingly, the Commission should carefully weigh the operational, implementation, and compliance risks associated with such a fundamental change in approach against the PRP's established replacement methodology, which is already advancing the retirement of CI/DI facilities in a manner fully consistent with the Commission's directive.

[2] In response to NSG-PGL-PIRG 4.18 (NSG-PGL Ex. 31.7), Dr. Lewnard confirmed that he has not personally designed, managed, overseen, or consulted on a CIPL rehabilitation project on a natural gas distribution system and that his knowledge regarding large-scale urban CIPL deployment is based on academic and industry research. In response to NSG-PGL-PIRG 4.23 (*id.*), Dr. Lewnard was unable to identify any gas distribution utility in the United States that has deployed ASTM F3777-25-compliant CIPL on more than 10 miles of pipe. These responses underscore the lack of demonstrated utility-scale precedent for the deployment strategy he recommends in this proceeding.

Q. Mr. Lewnard also asserts that PGL's double-decking strategy "exacerbates threats" by doubling miles of plastic pipe subject to excavation damage. PIRG Ex. 8.0 at 28–29. How do you respond?

A. Mr. Lewnard's characterization conflates the presence of additional pipe miles with an actual increase in system risk. Double-decking—installing new polyethylene pipe alongside the existing main—provides resiliency, operational flexibility, and the ability to serve both existing and future load requirements, including facilitating the LP to MP conversions that improve long-term system safety and operational efficiency. Modern polyethylene pipe installed through horizontal directional boring is buried at depths and in configurations that make it materially less susceptible to excavation damage than open-cut installations in congested urban utility corridors.

Moreover, Mr. Lewnard's reliance on PGL's DIMP Appendix I risk scores to argue that CIPL addresses the Company's stated risks "much like replacement would, and perhaps better" (PIRG Ex. 8.0 at 26) misreads that document. The DIMP identifies excavation damage and equipment malfunction as top threats, but replacement—unlike CIPL—facilitates concurrent replacement of deteriorated services, installation of excess flow valves, and MP conversion, each of which addresses discrete threat categories beyond the host pipe itself. PGL's double-decking strategy does not simply double exposure; it replaces aging, leak-prone infrastructure with modern materials installed at protective depths while simultaneously enabling systemic operational improvements that CIPL cannot deliver.

Mr. Lewnard's comparison also ignores critical differences between the two approaches. CIPL retains the original CI/DI host pipe geometry and does not add system

redundancy, does not address service line connections requiring renewal, and does not facilitate the pressure upgrades that improve operational safety and enable future system flexibility. The Company's DIMP threat assessment accounts for excavation risk on all pipe materials, and the Company employs comprehensive damage prevention programs—including one-call participation, facility marking, and public awareness campaigns—to mitigate that risk regardless of whether the replacement strategy involves double-decking or any other configuration.

Mr. Lewnard also newly asserts that PGL's JANA data for Phase II projects show that replacing existing black plastic services with new yellow plastic services "increased risk" for 8,631 of 14,346 assets. PIRG Ex. 8.0 at 36–37. This characterization is misleading. Those assets are existing plastic services being replaced to install excess flow valves—a safety enhancement the JANA methodology does not currently quantify. The Company explained in discovery that the JANA model does not incorporate the risk-reduction value of excess flow valve installation, and the negative mitigation scores therefore reflect a modeling limitation rather than an actual increase in system risk. The replacement of black plastic services with yellow plastic equipped with excess flow valves is a recognized safety improvement required by PHMSA guidance.

Q. Mr. Lewnard further argues that CIPL meeting ASTM F3777-25 produces a 50-year service life and therefore constitutes "retirement" of the host pipe. PIRG Ex. 8.0 at 20–22. Does the Company dispute that ASTM F3777-25 represents progress in establishing CIPL performance criteria?

A. No. As stated above, the Company does not dispute that ASTM F3777-25 represents progress in quantifying CIPL performance criteria. However, Mr. Lewnard's new assertion that the Company's participation in the Testing and Technical Specifications Panel ("TTSP") for the ARPA-E REPAIR program obligates it to accept CIPL as satisfying the retirement directive (PIRG Ex. 8.0 at 22–23) is misplaced. PGL's participation in a voluntary industry standards-development process reflects responsible engagement with emerging technology—it does not constitute an admission that CIPL satisfies the Commission's specific retirement directive, which was established under a separate regulatory framework and involves distinct compliance-tracking requirements. The regulatory question—whether a lined CI/DI pipe ceases to be a regulated distribution asset requiring integrity management and DIMP reporting—remains unanswered by ASTM F3777-25 or the TTSP process. PHMSA itself has not reclassified rehabilitated pipe out of the "Reconditioned Cast Iron" category, notwithstanding the development of the standard. The Company reiterates its request that the Commission provide the regulatory clarity both Peoples Gas and PIRG agree is needed.

Until that clarity is provided, it would be imprudent for Peoples Gas to redirect billions of dollars of program planning toward an approach whose regulatory compliance status remains undefined. Once the Commission provides direction on whether CIPL deployment satisfies the retirement directive, the Company will incorporate that guidance

into future project evaluations and credit CIPL toward the 2035 compliance target where appropriate.

Q. PIRG witness Lewnard asserts that PGL's evaluation of CIPL in the PARs constitutes "blanket and incorrect assertions" rather than genuine alternatives analysis, and that PGL "did not find even one opportunity for CIPL." PIRG Ex. 8.0 at 6–7, 9. How do you respond?

A. Mr. Lewnard's characterization is incorrect. As a threshold matter, the Company has in fact deployed CIPL on prior projects—specifically, the Canalport and South Shop projects discussed earlier in this section and presented in detail in NSG-PGL Ex. 31.6. Those case studies demonstrate that the Company evaluates and selects CIPL where project-specific conditions favor it.

The Company's alternatives analysis in each PAR evaluates applies the same project-specific framework described above—evaluating constructability, customer outage duration, host pipe condition, regulatory uncertainty regarding the retirement directive, and system integration requirements. Where those factors favor CIPL, the Company selects it—as Canalport demonstrates. Where they do not, the Company documents why and proceeds with replacement or insertion—as South Shop demonstrates.

The fact that the Phase I projects at issue—which were designed under the SMP and are located in dense urban environments requiring LP to MP conversion—were not suitable for CIPL does not mean the Company categorically rejects CIPL for all future projects.

Mr. Lewnard further asserts that PGL "caused its own delay by not evaluating alternatives earlier, even when prompted by the Commission at various points over the last several years to consider alternatives to retirement." PIRG Ex. 8.0 at 15. This criticism is unpersuasive. The Commission's prior references to alternatives and NPAs did not constitute a directive to defer retirement of CI/DI pipe pending evaluation of unproven technologies. To the contrary, the Commission in its 2024 SMP Investigation Order directed PGL to accelerate CI/DI retirement—the very directive that now compels the pace of the PRP. The Company cannot simultaneously be faulted for failing to meet prior retirement timelines and for not pausing retirement to evaluate technologies whose regulatory status under the Commission's directive remains undefined. The Company's approach—proceeding with proven replacement methods while developing the NPA framework and seeking Commission clarification regarding CIPL's status—is the only path consistent with both the retirement directive and prudent utility practice.

IX. THE JANA RISK MODEL AND COST-EFFECTIVENESS

Q. PIRG witnesses Drs. Lesser and Feinstein assert that PGL has "failed to demonstrate" that its proposed PRP investments are cost-effective and that third parties cannot reproduce the Company's JANA risk analysis. How do you respond?

A. The JANA probabilistic risk model is a well-established, validated tool that the Commission expressly permitted PGL to use in the 2024 SMP Investigation Order. PGL employs the model as one component of a larger decision-making framework that also incorporates engineering judgment, project-by-project alternatives analysis, constructability assessment, and cost evaluation. The Company's Priority Risk Reduction Method ("PRRM") provides a transparent, quantifiable basis for sequencing: it eliminates a piping system's highest-risk CI/DI assets after retiring approximately 188 miles of pipe, compared with approximately 617 miles under a simple average-risk approach—demonstrating substantially more efficient, targeted risk reduction. To the extent Drs. Lesser and Feinstein raise purely technical critiques of the model's internal methodology, those are addressed by the rebuttal and surrebuttal testimony of Messrs. DuQuesnay and Mayberry of the JANA Corporation (NSG-PGL Ex. 28.0; NSG-PGL Ex. 42.0). The Company conducted an in-person meeting with PIRG's experts on June 11, 2026, at which it presented the complete risk calculation methodology, example calculations, model parameter configurations, and model outputs and validation. This level of transparency—which went well beyond what is typically required in utility ratemaking—demonstrates the Company's commitment to engaging with stakeholders to explain its

processes and procedures. Any remaining claims of non-reproducibility must be evaluated in light of these disclosures.

Q. Should the Commission condition PRP cost recovery on a monetized benefit-cost or cost-effectiveness screen, as PIRG suggests?

A. No. The Commission has established a mandatory directive requiring PGL to retire all qualifying CI/DI pipe under 36 inches by a date certain. A framework that conditions investment on whether each project clears a monetized benefit-cost threshold cannot be squared with a directive that requires comprehensive system retirement regardless of relative ranking. When the Company asked PIRG in discovery how its proposed framework accounts for the directive—"a mandate that requires PGL to address all qualifying pipe, not merely the pipe yielding the highest benefit-cost ratio"—PIRG did not provide a substantive response, citing only a prior passage in its testimony. *See* NSG-PGL Ex. 17.23 (PIRG response to Companies data request NSG-PGL-PIRG 1.04(c)). Nor has PIRG identified any utility subject to a comparable mandatory retirement requirement that relies on a monetized benefit-cost framework as the sole or primary basis for selecting projects. The appropriate measure of prudence here is whether the Company directed capital to the highest-risk assets consistent with the directive—which the PRRM and the project-level documentation demonstrate that it did.

Q. Drs. Lesser and Feinstein assert in rebuttal that PGL's PRP investments produce a benefit-cost ratio of approximately 0.01—that is, approximately one penny in quantified risk-reduction benefit per dollar spent. PIRG Ex. 7.0 at 12. Does this analysis undermine the PRP?

A. No. The analysis does not demonstrate that the PRP lacks value or that the Commission should reconsider its retirement directive.

As an initial matter, Drs. Lesser and Feinstein acknowledge that the benefits used in their calculation are the mitigated-risk values produced by the JANA model. In discovery, they confirmed that their benefit calculation is based on the mitigated risk calculated by the JANA model and stated that those mitigated-risk values incorporate the consequence categories defined by the JANA model for Peoples Gas, including avoided property damage, personal injury and fatality, service disruptions, emergency response costs, leak-survey costs, and corrosion-control costs. NSG-PGL Ex. 31.7 (PIRG response to Companies data request NSG-PGL-PIRG 4.03). Accordingly, the disagreement is not whether those consequence categories exist, but whether PIRG's application of the JANA outputs provides a reasonable basis for evaluating a Commission-mandated safety program.

The analysis nevertheless does not provide a sound basis for judging the prudence or effectiveness of the PRP. Drs. Lesser and Feinstein rely on a single monetized comparison between projected PRP expenditures and a present-value estimate of future mitigated risk. That comparison reduces a multi-decade safety and infrastructure modernization program to a single financial ratio and ignores the broader policy considerations underlying the Commission's retirement mandate. The Commission

directed Peoples Gas to retire its remaining CI/DI facilities because of the systemic safety, reliability, and operational risks associated with aging leak-prone infrastructure—not because any individual project was expected to satisfy a particular benefit-cost threshold.

Most importantly, PIRG cannot identify any instance in which a regulatory commission has rescinded or reconsidered a previously issued safety-related infrastructure mandate based on a benefit-cost analysis. Further in discovery, Drs. Lesser and Feinstein stated that they are aware of no such precedent. *Id.* (PIRG response to Companies data request NSG-PGL-PIRG 4.05(c)). Thus, PIRG asks the Commission to give controlling weight to a benefit-cost framework that, by PIRG's own admission, has never been used to overturn a previously established safety directive.

The Commission has repeatedly recognized the safety and reliability benefits associated with retiring aging CI/DI infrastructure. The relevant question in this proceeding is therefore not whether PIRG can derive a particular benefit-cost ratio from selected model outputs, but whether Peoples Gas prudently continued to implement the Commission's retirement mandate using reasonable planning, engineering, and project-selection practices. PIRG's 0.01 ratio does not establish that the PRP lacks value, nor does it provide a basis for denying recovery of prudent investments made to comply with existing Commission directives.

Q. Drs. Lesser and Feinstein also assert that the PRRM is flawed because ranking by average mitigated risk per foot would yield approximately 10% more risk reduction in fewer miles. PIRG Ex. 7.0 at 36. How do you respond?

A. PIRG's criticism reflects a fundamental disagreement about the objective of the PRRM. The PRRM is not designed to maximize a single mathematical metric in isolation. Rather, it is designed to retire all Commission-mandated CI/DI facilities by January 1, 2035 in a manner that maximizes risk reduction while remaining operationally feasible, cost-effective, and consistent with the physical realities of an integrated gas distribution system.

PIRG's alternative ranking methodology focuses exclusively on average mitigated risk per foot. While that metric may be useful as one analytical input, it cannot serve as the sole basis for sequencing a system-wide retirement program. CI/DI retirement is not performed one pipe segment at a time in isolation. Piping systems must be retired as functional units to maintain hydraulic integrity, avoid stranded or orphaned facilities, facilitate LP-to-MP conversions, coordinate service renewals and reconnections, and capture the construction efficiencies that arise from geographically contiguous work. A methodology that simply selects the highest-risk individual segments regardless of their relationship to the surrounding system would undermine those objectives and make implementation significantly more difficult and costly.

Moreover, PIRG's asserted 10% improvement in risk mitigation is based on a comparison confined to a defined number of miles, not the Commission's full retirement program the Commission has mandated. In response to Companies Data Request NSG-PGL-PIRG 4.08(c), Drs. Lesser and Feinstein confirmed that "if all pipe is retired, the

total risk reduction is the same regardless of ranking," and that their claimed improvement instead reflects only that their alternative "reduces risk more rapidly" for a given number of miles retired. *See* NSG-PGL Ex. 31.7 (PIRG response to Companies data request NSG-PGL-PIRG 4.08(c)).

In other words, once the Commission's mandate that all qualifying CI/DI facilities be retired by January 1, 2035 is taken into account, PIRG's own discovery response confirms that its proposed re-ranking would not increase the total quantity of risk ultimately mitigated—only its pace and sequencing for a partial subset of miles. The question before the Commission is therefore not how to maximize risk reduction for some subset of miles, but how to sequence the retirement of the entire remaining CI/DI system in the most reasonable and effective manner. PIRG's assertion that ranking by total risk would mitigate $2.7 million versus the PRRM's $598,616 for the top ten pipe systems (PIRG Ex. 7.0 at 39) illustrates the same point: it is a comparison confined to a subset of pipe systems, not the full 289-system retirement the Commission has directed. Because all 289 pipe systems will ultimately be retired regardless of ranking, the sequencing question affects only the order and timeline of retirement, not the total quantity of risk ultimately mitigated. In a mandatory comprehensive-retirement program, the PRRM's focus on eliminating the highest-risk individual assets earliest produces the greatest near-term safety benefit precisely because it prioritizes the most dangerous pipe—not merely the largest pipe systems.

In addition, in response to Companies Data Request NSG-PGL-PIRG 4.06 (NSG-PGL Ex. 31.7), Drs. Lesser and Feinstein were unable to identify any gas utility that has implemented their proposed ranking methodology as the basis for a mandatory pipe-

replacement or retirement program. Nor did they demonstrate that the methodology can be operationalized within a piping-systems-based retirement framework that requires retirement of contiguous facilities to support pressure conversion, system integration, and completion of retirement objectives. Thus, PIRG's proposal remains a theoretical exercise rather than a demonstrated replacement-program methodology.

Ultimately, PIRG's analysis shows only that a different metric would produce a different ranking. It does not demonstrate that the PRRM is unreasonable, that the Companies' retirement sequencing is imprudent, or that the Commission's 2035 retirement objective can be achieved more effectively through PIRG's untested approach. To the contrary, the PRRM strikes the appropriate balance between risk reduction and the operational realities of retiring an entire urban CI/DI distribution system—a balance that is consistent with the Commission's guidance in the 2024 SMP Investigation.

Q. Drs. Lesser and Feinstein assert that PGL's projected $5 billion program cost yields risk-reduction benefits of "less than $200 million on a present value basis—roughly five cents on the dollar." PIRG Ex. 7.0 at 47. Is that characterization accurate?

A. No. A mandatory safety directive is not subject to a benefit-cost screen. The Commission's retirement order requires retirement of all qualifying CI/DI facilities by 2035. PIRG has identified no precedent for rescinding such a mandate based on a retrospective benefit-cost analysis. The appropriate question before this Commission is whether the Company is executing the directive prudently—not whether the directive itself passes a cost-benefit test that was never a precondition for its adoption.

X. NON-PIPELINE ALTERNATIVES AND HYDRAULIC FEASIBILITY

Q. PIRG witness Dr. Walsh and City witness Mr. Lander contend that PGL has failed to develop a timely NPA framework, and Dr. Walsh's analysis of the Irving Woods Phase 9 project asserts that several NPA pathways are cost-competitive with replacement. How do you respond?

A. Peoples Gas takes NPAs seriously and has taken significant steps to develop a rigorous framework for evaluating them. The Company retained CRA to develop a comprehensive NPA screening and evaluation framework, has committed to completing that work in 2026, and intends to incorporate NPA screening into Phase II project planning beginning in 2027. The Company is therefore not rejecting NPAs; rather, it is establishing an analytical process to evaluate them consistently and objectively before deployment.

At the same time, the evidence demonstrates that NPAs are unlikely to materially adjust the scope of the PRP within the Commission's required retirement timeframe. As The Brattle Group explains, Peoples Gas operates a highly integrated, high-density urban distribution network, which substantially limits the opportunities for customer-electrification or other demand-side alternatives to defer or eliminate major retirement projects. Moreover, many of the projects included in the 2026 and 2027 work plans are driven by aging infrastructure, elevated risk conditions, and the need to continue progressing toward the Commission's requirement that all qualifying CI/DI facilities be retired by January 1, 2035. Indeed, under Dr. Walsh's own framework, many such projects would fall within the category of projects for which it is effectively too late to deploy an NPA. Requiring mandatory NPA "gating" before the Company's framework is

complete would therefore divert resources from the Commission's primary objective without any demonstrated benefit.

With respect to the Irving Woods Phase 9 project specifically, Dr. Walsh's analysis does not establish that an NPA represents a feasible substitute for the planned infrastructure investment. His levelized-cost comparison focuses on theoretical cost estimates but does not account for several practical considerations, including customer adoption uncertainty, implementation timing, the operational characteristics of Peoples Gas' interconnected LP network, and the challenges associated with deploying alternatives at a scale sufficient to avoid or defer the project. Moreover, while Dr. Walsh identifies a propane-based pathway with a (purported) lower levelized cost than pipeline gas service, propane is not a permanent one-for-one substitute for a dense urban gas distribution system and raises separate questions regarding permitting, storage, operational feasibility, and long-term customer impacts.

To test those assumptions, Peoples Gas sought additional information regarding the propane scenario underlying Dr. Walsh's analysis. In response to Companies data request NSG-PGL-PIRG 4.24 (NSG-PGL Ex. 31.7), Dr. Walsh confirmed that the $21.86 per MMBtu propane benchmark assumes individual, truck-delivered, on-site tank service—the standard residential propane delivery configuration—rather than a community propane system, and that Municipal Code of Chicago § 15-26-540 does not restrict liquefied petroleum gas use in residential buildings with fewer than 20 occupants, such as single-family dwellings. Dr. Walsh further confirmed that his analysis already includes an upfront propane-conversion cost of $5,000 per customer (covering furnace replacement and tank installation), presented separately from the $21.86 per MMBtu

fuel-price figure to avoid double-counting, and contends that even accounting for any other cost items not separately itemized, the comparison remains "conservative" because the levelized cost of delivered gas under the pipe-replacement scenarios ($43.28 to $83.84 per MMBtu) exceeds the propane benchmark by a margin large enough to absorb any plausible additional cost. *See* NSG-PGL Ex. 31.7 (PIRG response to Companies data request NSG-PGL-PIRG 4.24).

Notwithstanding these confirmations, Dr. Walsh's analysis does not establish that an NPA represents a feasible substitute for the Irving Woods Phase 9 project specifically. His $21.86 per MMBtu benchmark is derived from average weekly Illinois residential propane prices between October 2021 and March 2026—a period Dr. Walsh acknowledges reflects "high global energy market volatility" attributable to the Ukraine and Iran conflicts—and does not reflect the price volatility or supply-security risk of relying on truck-delivered propane for permanent service to a dense urban LP network. Nor does the code provision Dr. Walsh identifies resolve permitting, siting, and safety questions for building types, occupancies, and site conditions in the Irving Woods Phase 9 project area that may exceed the 20-occupant threshold under Municipal Code of Chicago § 15-26-540. In that event, the Irving Woods analysis would demonstrate only that a simplified theoretical model can produce a lower estimated cost for a subset of qualifying buildings—not that a real-world, code-compliant alternative can reliably replace the proposed project for the project area as a whole.

Ultimately, the question is not whether a hypothetical NPA can be modeled as cost-competitive under a particular set of assumptions. The question is whether an alternative can be implemented safely, reliably, and lawfully while continuing to satisfy

the Commission's retirement directive and maintain service to customers. The record does not demonstrate that Dr. Walsh's proposed alternatives can do so. Peoples Gas will continue to evaluate NPAs on both a project-specific and system-wide basis as the CRA framework is finalized and as directed by the Commission, but nothing in the intervenors' analyses provides a basis for delaying or disallowing prudent PRP investments needed to satisfy the Commission's mandate.

Q. PIRG witness Mr. Brown recommends that PGL adopt a holistic, system-wide hydraulic optimization using genetic algorithms and mixed-integer optimization. Is that recommendation feasible and necessary?

A. No. Mr. Brown's recommendation is neither necessary to support implementation of the PRP nor practical to deploy within the timeframe established by the Commission. Peoples Gas already performs comprehensive hydraulic modeling using the Synergi platform and relies extensively on hydraulic analysis in planning and sequencing system retirements. Indeed, the Company's piping-systems-based approach was itself developed through hydraulic analysis, which was used to identify and define the 289 piping systems that form the foundation of the PRP. Many of the analytical considerations Mr. Brown presents as enhancements—including pressure-drop evaluation, pressure-conversion planning, and system-capacity analysis—are already incorporated into the Company's planning process.

The principal difference is that Mr. Brown advocates for a highly automated, system-wide optimization framework using advanced techniques such as mixed-integer optimization and genetic algorithms to identify an "optimal" retirement sequence. Mr.

Brown acknowledged that such methods are not commonly used in the gas-distribution industry for planning large-scale pipe-retirement programs. The relevant question is therefore not whether such a framework could theoretically be developed, but whether requiring its development would meaningfully improve the PRP and justify the resources and delays associated with implementation.

The evidence does not support Mr. Brown's recommendation. In response to Companies Data Request NSG-PGL-PIRG 4.25, Mr. Brown identified no gas distribution utility that has implemented the parametric optimization methods he recommends at a scale comparable to Peoples Gas's approximately 4,000-mile distribution network; instead, he pointed to his own experience developing the capability, largely in-house, at Pacific Gas and Electric Company, a system he describes as roughly ten times PGL's size. *See* NSG-PGL Ex. 31.7 (PIRG response to Companies data request NSG-PGL-PIRG 4.25(c)). That precedent does not establish that the methodology is achievable for PGL on the relevant timeline and with the relevant resources: PG&E's capability was developed over approximately two to three years using a combination of a contractor and two to three internal engineering FTEs, in support of both transmission and distribution applications on a system with roughly ten times PGL's mileage and customer base—resources and a development runway that are not interchangeable with a program that must also execute nearly 1,000 miles of physical CI/DI retirement by 2035.

In response to NSG-PGL-PIRG 4.26, Mr. Brown estimated 12 to 24 months to reach initial operational capability and contended that this timeline is compatible with the 2035 deadline because Level 1 and Level 2 NPA screening can proceed in the interim using PGL's existing hydraulic models, because a vendor-led effort would not divert

PGL's own engineering resources, and because he has had only preliminary, non-binding discussions with DNV regarding a possible multi-utility development partnership. *See* NSG-PGL Ex. 31.7 (PIRG response to Companies data request NSG-PGL-PIRG 4.26(b)-(d)). Mr. Brown has not obtained, and does not offer, any vendor proposal, scope of work, cost estimate, or committed timeline specific to PGL's system. Given that no concrete vendor commitment, budget, or implementation plan exists, the Commission should not condition or delay PRP execution on a still-theoretical capability whose development path—by Mr. Brown's own account—depends on a multi-utility partnership that has not yet been formed. By contrast, the Company's existing PRRM and piping-systems-based methodology are operational today and have already guided identification of the 289 piping systems that form the foundation of the PRP.

More fundamentally, Mr. Brown does not demonstrate that the existing PRRM and piping-systems-based methodology are producing unreasonable results. The Commission has directed Peoples Gas to complete retirement of all qualifying cast iron and ductile iron facilities by January 1, 2035. That directive requires an approach that is executable today, not a multi-year effort to develop and validate an unproven optimization capability that no similarly situated utility has adopted. Theoretical improvements in sequencing are of limited value if they cannot be implemented in a timely and reliable manner within the constraints of an ongoing retirement program.

Accordingly, while Peoples Gas should continue to evaluate improvements to its analytical tools as technology evolves, the record does not support delaying, restructuring, or conditioning the PRP on the development of a sophisticated optimization

framework that lacks demonstrated utility-scale precedent and offers no proven path to materially improving compliance with the Commission's retirement directive.

Q. City witness Mr. Lander proposes that the Commission direct PGL to publish interactive CI/DI retirement maps within six months of the Final Order, file a formal NPA framework within six months aligned with PIRG, and direct a PGL–ComEd joint gas-electric planning workshop. How do you respond to these recommendations?

A. We appreciate Mr. Lander's constructive engagement and note that he proposes no revenue-requirement disallowance. With respect to CI/DI retirement maps, the Company has agreed in principle to provide mapping information and is willing to publish retirement area maps on a timeline that accounts for operational security considerations and data preparation. With respect to the NPA framework timeline, the Company has retained CRA and is developing the framework on an expedited basis; a rigid six-month deadline imposed without regard to the framework's analytical quality could produce a superficial product. The Company commits to completing and filing the framework at the earliest practicable date and to applying it to Phase II projects beginning in 2027. With respect to PRP reporting metrics, we agree with Mr. Lander that the existing Docket No. 16-0376 template should be treated as a baseline subject to refinement after the Safety Monitor's March 2027 report—and we note that Mr. Lander expressly disclaims relitigating Docket No. 16-0376 in this proceeding. COC Ex. 2.00 at 2. The appropriate forum for revised PRP reporting metrics remains the reopened metrics proceeding. Finally, the joint gas-electric planning workshop is more appropriately addressed through

the Commission's Future of Gas Pilots proceeding (Docket No. 26-0067), where all Illinois utilities—not just PGL—can participate on a coordinated basis.

Q. Mr. Lander also recommends that the Commission treat the current PRP reporting template in Docket No. 16-0376 as interim and revisit it after the Safety Monitor's March 2027 report. COC Ex. 2.0 at 2–5. What is the Company's position?

A. The Company agrees with Staff (Staff Ex. 13.0 at 10) that the reopened metrics proceeding in Docket No. 16-0376 is the appropriate forum for determining any modifications to PRP reporting metrics. The Company also agrees that the Safety Monitor's March 2027 report may provide useful information for evaluating potential refinements to the reporting framework. However, the Company does not agree that the existing reporting template should be characterized as merely interim. The reporting framework will become the Commission-approved mechanism for monitoring PRP performance unless and until it is modified in the reopened Docket No. 16-0376 proceeding. As Mr. Lander acknowledges, this rate case is not the appropriate forum to revisit the reporting framework. Rather, any proposed revisions should be considered in the reopened metrics proceeding, where stakeholders can fully evaluate the Safety Monitor's recommendations and collaboratively develop any appropriate changes to the reporting metrics.

Q. City witness Mr. Lander raises a concern that PGL's NPA evaluation process uses Class 5 estimates for all alternatives at the screening stage but then advances only the replacement option to Class 3—meaning that if cost escalation occurs during design refinement, NPAs screened out at Class 5 are never reconsidered. COC Ex. 2.0 at 6–8. How do you respond?

A. The Company evaluates all alternatives—including replacement, CIPL, and non-pipeline alternatives—at Class 5 with 30% unallocated contingency to ensure an apples-to-apples comparison at the screening stage. This approach is consistent with standard engineering practice: screening-level estimates are intended to identify the most promising alternative for further development, not to provide definitive cost figures for all options. Advancing all alternatives to Class 3 simultaneously would require significant additional engineering resources without a demonstrated need.

That said, the Company's governance process is not static. To the extent Class 3 refinement reveals costs materially exceeding the Class 5 estimate, the Company's project governance process includes a review trigger that considers whether the selected alternative remains optimal relative to the alternatives screened at Class 5. The Company does not object to enhanced NPA reporting as recommended by both Staff and the City, and will incorporate NPA evaluation documentation in future PRP filings.

XI. TARGETED ELECTRIFICATION

Q. CUB witness Mr. Velez proposes creating a targeted electrification "track" within the PRP that would proactively decommission lower-risk blocks alongside the riskiest-first retirement work. How do you respond?

A. We note at the outset that Mr. Velez clarified on rebuttal that his proposal requests a study and a plan—not an immediate program. CUB Ex. 8.0 at 4–7. We appreciate that clarification, and it narrows the dispute. However, even a study-and-plan directive presents concerns in this proceeding.

First, decommissioning feasibility is fundamentally a network-wide hydraulic problem that cannot be assessed on a project-by-project basis within the PRP—and the Company's NPA framework, being developed with CRA, is the appropriate analytical vehicle for that system-wide assessment. Mr. Velez argues that CRA's project-level NPA framework cannot substitute for a system-wide study because "whether it is hydraulically feasible to decommission a particular pipe segment depends on which adjacent segments have already been decommissioned" (CUB Ex. 8.0 at 11). While the Company acknowledges the network interdependency of decommissioning decisions, this observation supports—rather than undermines—developing the NPA framework first: a comprehensive system-level analysis requires precisely the analytical infrastructure, data inputs, and evaluation criteria that the CRA framework is being designed to produce. Conducting a standalone hydraulic feasibility study in the absence of that framework would lack the evaluation criteria necessary to translate its results into actionable program decisions.

Second, Mr. Velez's finding that approximately 14.3% of fully residential PRP blocks (213 of 1,488) are strictly cheaper to electrify than to replace pipe rests on a per-home cost estimate of $28,706 drawn from ComEd's CY2024 Cost-Effectiveness Analysis, which assumes 100% customer participation without identifying any mechanism to achieve it and does not assess hydraulic feasibility, load impacts, or implementation timelines in PGL's dense urban network.

Third, Mr. Velez acknowledges that PGL's riskiest-first project selection is structurally incompatible with targeted electrification at scale—and the Company agrees that for higher-risk segments, delaying action to evaluate or coordinate electrification would be inconsistent with the Commission's directive to prioritize safety. This structural incompatibility is precisely why a study should be conducted through the NPA framework and future proceedings, not layered onto the PRP in this rate case. Mr. Velez's suggestion that PGL has a "clear financial incentive" to avoid revealing system-level decommissioning potential (CUB Ex. 8.0 at 11) is unfounded. The Company has voluntarily committed to developing the CRA NPA framework, has agreed to evaluate targeted electrification as a category of NPA for Phase II, and has not resisted the Commission's Future of Gas proceeding where these issues are being comprehensively examined. That said, targeted electrification will be among the NPAs considered as the Company's NPA framework matures, and the Company does not object to the Commission directing that the CRA framework incorporate targeted electrification as a category of NPA for Phase II evaluation.

Q. Mr. Velez also argues that replacing pipe on blocks where customers may eventually electrify creates stranded-asset risk and accelerates a "natural gas death spiral." Does that justify deferring retirement of leak-prone pipe?

A. No. The Commission's retirement directive is grounded in safety, and Peoples Gas must ensure safe and reliable service for its current customers. Deferring replacement of leak-prone pipe based on uncertain future demand trends would be inconsistent with prudent utility practice and with the Commission's directive. The appropriate response to long-term demand uncertainty is to develop the NPA framework that will allow the Company to make informed future-investment decisions as demand trends become clearer, while seeking appropriate regulatory mechanisms for cost recovery—not to underinvest in safety-critical infrastructure today.

XII. METHANE EMISSIONS, LEAK DETECTION, AND ENVIRONMENTAL JUSTICE

Q. EDF witness Dr. Joseph von Fischer recommends that Peoples Gas adopt AMLD, make greater use of leak data, provide more detailed emissions reporting, and consider financial incentives, and he raises environmental justice considerations. How do you respond?

A. As an initial matter, Dr. von Fischer does not challenge the PRP's programmatic structure or the Commission's retirement directive, and we appreciate that area of agreement. We also agree that reducing methane emissions is an important objective—and the PRP advances it directly. The retirement of aging, leak-prone CI/DI main is itself one of the most significant methane-emissions-reduction measures available to the Company, and

Peoples Gas has incorporated emissions reduction into the design and execution of the PRP. The Company will continue to evaluate enhanced leak-detection practices as part of its PRP planning. The additional requirements Dr. von Fischer proposes, however, are not necessary to ensure that the PRP achieves its safety and environmental objectives, which the accelerated retirement of CI/DI pipe accomplishes on its own.

Q. Are Dr. von Fischer's broader recommendations appropriately addressed in this rate case?

A. No. Dr. von Fischer's broader policy proposals—regarding AMLD, leak-data utilization, detailed emissions reporting, and financial incentives—raise system-wide questions that extend well beyond the prudence of the PRP investments at issue in this rate case. They are more appropriately addressed in the Commission's Future of Gas proceeding (Docket No. 24-0158) and/or the reopened PRP metrics proceeding (Docket No. 16-0376), where reporting metrics are already being developed. We note that Dr. von Fischer has moderated his incentive-framework proposal on rebuttal, now recommending that stakeholders develop recommendations to the Illinois General Assembly rather than proposing a Commission-ordered mechanism in this case—an acknowledgment that these issues exceed the scope of a rate case.

Q. Dr. von Fischer presents a new regression analysis in rebuttal purporting to show a statistically significant correlation between leak density and community-area percentage of people of color (rate ratio approximately 1.15, p=0.012). EDF Ex. 2.0 at 19–27. How does the Company respond to these environmental justice findings?

A. The PRP already directs investment toward the highest-risk aging infrastructure throughout the system. As those facilities are replaced, the resulting safety and emissions-reduction benefits accrue to all communities served by that infrastructure, including the communities identified by Dr. von Fischer. The Company remains willing to work with stakeholders on appropriate data reporting that may inform future environmental justice analyses.

Q. Dr. von Fischer recommends annual geographically-specific leak and asset data reporting and provides a detailed reporting specification in EDF Ex. 2.06. EDF Ex. 2.0 at 39–43. Does the Company oppose enhanced data transparency?

A. No. The Company is not opposed to transparency and has already provided extensive leak and asset data in this proceeding. The Company agrees that annual leak reporting should continue and does not object to reasonable refinements to that reporting as the program evolves.

Regarding the detailed reporting specification in EDF Ex. 2.06, the Company requests that the appropriate forum for finalizing data specifications be the reopened PRP metrics proceeding in Docket No. 16-0376, where reporting requirements can be developed collaboratively with all stakeholders—including Staff, the AG, the City, EDF, PIRG, and CUB—rather than adopted on the basis of one party's proposal in a rate case.

Collaborative development of reporting standards will produce specifications that are technically feasible, operationally implementable, and responsive to the needs of all interested parties. The Company is prepared to participate constructively in that process.

Q. Dr. von Fischer recommends that Peoples Gas operationalize AMLD leak-location data in addition to quantification data, and potentially increase the AMLD budget to support expanded deployment. EDF Ex. 2.0 at 36–38. What is the Company's position?

A. The Company values AMLD as a tool for quantifying methane emissions before and after construction and will continue deploying it for that purpose. The Company is willing to evaluate whether operationalizing AMLD leak-location data in conjunction with its existing leak survey program can improve detection efficiency without disrupting PRP scheduling or diverting field resources from planned retirement work. The Company does not oppose reasonable adjustments to the AMLD budget if the Commission directs expanded deployment. However, restructuring program prioritization around AMLD data rather than the JANA risk model would be inconsistent with the system-level, risk-based approach the Commission approved in the 2024 SMP Investigation Order. AMLD data can complement the JANA model by identifying acute leak conditions that may warrant accelerated attention, but it should not supplant the comprehensive risk framework that governs project sequencing.

Q. Does this complete your surrebuttal testimony?

A. Yes.