STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

The Peoples Gas Light and Coke Company	)	
	)	Docket No. 26-0065
Proposed General Increase in Rates and Revisions to Other Terms and Conditions of Service	)	
North Shore Gas Company	)	
	)	Docket No. 26-0066
Proposed General Increase in Rates and Revisions to Service Classifications, Riders and Terms and Conditions of Service	)	(cons.)

DIRECT TESTIMONY OF
DR. SOL DELEON

ON BEHALF OF

ILLINOIS STATE PUBLIC INTEREST RESEARCH GROUP, INC.

May 5, 2026

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I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q: Please state your name, business name, and address.

A: My name is Sol deLeon. The business address for Synapse Energy Economics, Inc. is 485 Massachusetts Ave., Suite 3, Cambridge, Massachusetts 02139.

Q: By whom are you employed and in what capacity?

A: I am a Principal Associate at Synapse Energy Economics, Inc. I work primarily in Synapse's consulting for future of gas utilities practice, and I also work in the related area of building decarbonization technology and policy.

Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources, energy efficiency policies and programs, integrated resource planning, electricity market modeling and assessment, renewable resource technologies and policies, and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse's staff includes over 35 professionals with extensive experience in the electricity and gas industries.

Q: Please summarize your professional experience.

A: I have over 25 years of experience in the energy industry, primarily in U.S. natural gas distribution utilities and international merchant electricity generation. I analyze gas utility applications and filings before state public service commissions, in addition to developing studies, reports, and other materials regarding gas utility investments, business models, ratemaking, depreciation, revenue requirements, and business risk. Prior to joining Synapse, I was a project manager at Washington Gas & Light Company, working on initiatives for corporate governance, renewable natural gas ("RNG"), and greenhouse gas ("GHG") emissions reduction inventories. Before that, I worked for AES Corporation where I conducted risk analysis on commodity prices, interest rates and foreign exchange rates, developed models for derivative valuation and electric generating asset project valuation. I completed my Masters in Business Administration and my Doctorate in Liberal Studies at Georgetown University. My doctorate focused on energy transition and energy justice. My complete curriculum vitae is included at PIRG Exhibit 1.1.

Q: Have you testified before the Illinois Commerce Commission (the "Commission") previously?

A: Yes. I submitted testimony on behalf of the City of Chicago in People's Gas Light and Coke Company's ("PGL") rate case in Docket 23-0069.

Q: Was this testimony prepared by you or directly under your supervision?

A: Yes.

Q: Are you sponsoring any exhibits?

A: Yes, I am sponsoring the following exhibits:

- PIRG Exhibit 1.1: Curriculum Vitae of Dr. Sol deLeon;
- PIRG Exhibit 1.2: Compiled Discovery Responses; and
- PIRG Exhibit 1.3: Investment Depreciation Model Methodology.

II. INTRODUCTION TO PIRG'S WITNESSES

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

A: In this section of my testimony, I provide a high-level overview of the topics PIRG's direct witnesses address in PGL's proposed general increase in rates and revisions to service classifications, riders and terms of conditions of service (Docket No. 26-0065), and I present a table introducing those witnesses. PIRG's witnesses address topics that are deeply inter-related. My hope is the table below will make it easier for the Commission and parties to understand how the pieces of PIRG's direct case fit together.

Q: Please summarize the topics PIRG's direct witnesses address in this case.

A: PIRG's witnesses largely focus on the Company's capital investments, particularly through its Pipe Retirement Program ("PRP"). These witnesses evaluate the Company's decision-making, analyses, and proposals. Based on that evaluation, PIRG's witnesses make recommendations aimed at ensuring the Company's capital investments are in its customers' best interests.

Q: Please introduce PIRG's witnesses in this case.

A: The table below lists PIRG's witnesses, followed by exhibit numbers and the topics covered by their testimonies.

Witness	Exhibit No.	Topic(s)
Dr. Sol deLeon	PIRG Exhibit 1.0	Introduction to PIRG's witnesses Customer Impacts of the Pipe Retirement Program
Dr. Charles D. Feinstein Dr. Jonathan A. Lesser	PIRG Exhibit 2.0	Risk Assessment Methodology
John Lewnard	PIRG Exhibit 3.0	Risk Mitigation Activities and Pipeline Repair
Dr. Michael J. Walsh	PIRG Exhibit 4.0	Non-Pipeline Alternatives
Rick Brown	PIRG Exhibit 5.0	Hydraulic Feasibility Assessment

In addition to the witnesses above, PIRG also co-sponsors (with Legal Action Chicago and the City of Chicago) the testimony of witness David J. Garrett, who addresses rate of return.

III. PURPOSE OF TESTIMONY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to analyze the ratepayer impacts of PGL's proposed PRP in this proceeding and compare this to the ratepayer impacts of an illustrative alternative scenario where PGL relines certain pipes instead of replacing them. The purpose of my testimony also is to introduce other PIRG witnesses.

Q: Please summarize your findings.

A: My findings are the following:

- Modeling demonstrates that a meaningful reduction in capital expenditures from PGL's proposed PRP results in materially lower annual costs for ratepayers.

- The ratepayer impacts of PGL's proposed PRP are significant and grow materially over time. If PGL replaces all cast iron and ductile iron ("CI/DI") pipe less than 36" (inches) as proposed within the PRP, the incremental rate impact is projected to reach $0.60 per therm or $581 annually for a typical residential ratepayer by 2035, compared to $0.51 per therm or $500 annually under a lower capex scenario where PGL relines larger CI/DI pipe and replaces the smaller pipe. In 2050, the projected figures are $0.30 per therm or $295 for PGL's proposed PRP scenario and $0.26 per therm or $252 annually for the lower capex scenario.

Q: Are you proposing the Commission direct PGL to implement Scenario Two?

A: No. Again, my analysis is intended to illustrate the ratepayer impacts of PGL's proposed PRP, and contrast those impacts with an illustrative alternative scenario. The point is, ratepayers stand to benefit significantly from a less capital-intensive alternative PRP pathway. As I discuss in my testimony, those benefits intensify in a scenario where gas consumption and customer counts decline over time.

IV. BACKGROUND

Q: Please describe the Commission's directives to PGL regarding the System Modernization Program ("SMP").

A: In its final order on PGL's 2023 rate case, the Commission found that PGL's activities within the SMP were not adequately prioritizing the retirement of CI/DI pipe and directed PGL to pause the program until further investigation.[1] Following further investigation in

[1] Docket Nos. 23-0068 and 23-0069 (cons.), Final Order at 29-30 (Nov. 16, 2023).

Docket No. 24-0081, the Commission directed the Company to retire all CI/DI pipe under 36" in diameter by 2035 and develop a plan for doing so.[2]

Q: Please describe the Pipe Retirement Program.

A: The PRP is PGL's initiative to retire approximately 1,020 miles of CI/DI pipe less than 36" in diameter by the end of 2034, developed in response to the Commission's SMP Investigation Order issued in February 2025.[3] The PRP differs from the predecessor SMP in several respects. The legacy SMP took a proactive approach to replacement of all CI/DI pipe by neighborhood, in addition to targeted System Improvement, Public Improvement, Emergency, and High-Pressure projects.[4] In contrast, the PRP excludes pipe replacements falling in the latter four categories and prioritizes remaining CI/DI piping for replacement at the system level rather than the neighborhood level, prioritizing projects using the JANA probabilistic risk model. Under the PRP, PGL evaluates multiple system configurations, including permutations of low pressure/medium pressure, single/double decked, and existing/new services, for each piping system, while installing medium pressure regulators within upgraded buildings and forgoing meter relocation.[5]

[2] Docket No. 24-0081, Final Order at 97 (Feb. 20, 2025).
[3] NSG-PGL Ex. 3.0 REV at 8.
[4] *Id*. at 10-12.
[5] *Id.* at 20-21.

Q: What are PGL's proposed expenditures and activities for the PRP in this rate case?

A: PGL proposes to spend $210 million on the PRP in 2026 to retire 21 miles of pipe and spend $344.3 million in 2027 to retire 53 miles of pipe.[6] Table 1 shows PGL's projected expenditure and retirement mileage through 2029.

Table 1. PRP expenditure and retirement mileage 2026–2029

	2026	2027	2028	2029
Expenditure ($M nominal)	$210	$344	$532	$537
Miles retired	21	53	147	147

Source: 2026 and 2027 expenditure data from NSG-PGL Ex. 3.0 REV SUPP, page 4 and 15; 2028 and 2029 expenditure data from NSG-PGL Ex. 1.0 REV02; 2026 to 2029 retirement mileage from Data Request COC 1.20 in Docket No. 16-0376, included as PIRG Exhibit 1.2 at 1.

A. Alternatives to Replacement

Q: Please describe some of the alternatives to pipe replacement.

A: As discussed by PIRG witness Lewnard, there are many methods of long-term pipe repair and rehabilitation that provide equivalent safety benefits as pipe replacement and often at a lower cost.[7] Such repair technologies include cured-in-place liners ("CIPL") and joint sealing. Additionally, the use of non-pipeline alternatives ("NPAs") presents an opportunity to avoid infrastructure investments and sometimes abandon gas assets altogether.[8]

[6] NSG-PGL Ex. 3.0 REV SUPP at 4-5 and 15.
[7] Direct Testimony of Jack Lewnard, PIRG Ex. 3.0.
[8] Direct Testimony of Michael Walsh, PIRG Ex. 4.0.

Q: Does PGL consider pipe repair in the PRP?

A: No, PGL is not currently considering any pipe repair technologies as alternatives within the PRP,[9] arguing that repair would not eliminate the need to retire the CI/DI pipe under the PRP as directed by the Commission.[10] However, in regard to CIPL, PGL notes that "using CIPLs within segments of existing CI/DI pipe under 36 inches may (or may not) be deemed 'retirement' of those segments as the Commission intended that term to be understood in the retirement directive," and requests that the Commission provide clarification on this matter.[11]

Q: Please describe NPAs.

A: NPAs are solutions that meet customer energy needs and are alternatives to traditional infrastructure investments. NPAs could include demand-side measures such as electrification, energy efficiency, and other measures that reduce or eliminate customers' demand for natural gas or the need for pipe infrastructure.

Q: Has PGL evaluated NPAs for PRP projects included in this rate case?

A: Not yet. PGL is currently developing an NPA framework and expects to begin implementing the NPA framework for Phase II PRP projects starting in 2027.[12] For the purpose of this rate case, PGL retained the Brattle Group to provide feasibility and cost

[9] PIRG Ex. 1.2 (PGL Response to PIRG DR 5.04) at 4-5.
[10] PIRG Ex. 1.2 (PGL Response to PIRG DR 5.01) at 3.
[11] NSG-PGL Ex. 3.0 REV at 99 n.23.
[12] *Id.* at 100-101

assessments of various NPAs through an analysis that is intended to complement the future NPA framework.[13]

Q: What types of NPAs does PGL plan to evaluate?

A: While the exact NPA framework has not been finalized, PGL states that current NPA options to be considered include "geothermal systems, targeted electrification, and cured-in-place liners ('CIPLs')."[14] As I noted above, the Company expresses uncertainty around whether using CIPLs for CI/DI pipe under 36" aligns with the intent of the Commission's retirement directive.[15] However, even with this uncertainty regarding whether CIPL is considered "retirement," an NPA, or repair, PGL includes CIPL as a distinct option separate from NPAs in its example of future alternatives analysis for PRP projects.[16]

Q: Why is it important to consider the "alternatives to pipe replacement" in the context of ratepayer impacts?

A: PIRG witnesses Feinstein and Lesser, Lewnard, Brown, and Walsh each touch upon aspects of alternatives to pipeline replacement in their testimony, and they explain why and how the Company should be considering said alternatives.

In the context of ratepayer impacts, which is the subject of my testimony, PGL proposes a major increase in annual spending in this case. Specifically, as shown in Table 1, PGL's proposed PRP annual spending increases from $210 million in 2026 to $537 million in 2029. This level of spending will amount to $1.6 billion total over four years.

[13] NSG-PGL Ex. 7.0 REV02 at 4-5; NSG-PGL Ex. 1.0 REV02 at 22.
[14] NSG-PGL Ex. 3.0 REV at 99.
[15] *Id.* at 99 n.23.
[16] *Id.* at 104.

PGL cites the Commission's retirement directive as the reason for this massive increase in spending. If the PRP proposal is approved, the level of spending will have a significant impact on ratepayers, as I discuss below. PGL should proactively seek alternatives that mitigate the costs associated with the accelerated replacement of CI/DI pipe.

V. RATEPAYER IMPACT ANALYSIS

Q: What do you discuss in this section of your testimony?

A: In this section, I describe the analysis I conducted to calculate the incremental revenue requirement associated with PGL's proposed PRP investments (Scenario One) in comparison to an alternative scenario (Scenario Two) that uses a combination of pipe replacement and repair to address the remaining 1,020 miles of cast iron pipe <36" on PGL's system.

A. Methodology and Assumptions

Q: Please describe the model that you used to perform your analysis.

A: I used the Investment Depreciation Model, a model developed by Synapse based on a tool originally provided by Consolidated Edison Company of New York in New York Public Service Commission Case 14-E-0302. Inputs to the model include capital structure, costs of debt and equity, tax rates, tax schedule, net salvage rates, asset lives, and planned investments. The model calculates pass-through expenses (such as depreciation inclusive of net salvage) as well as rate base, defined as plant in service less book depreciation and deferred tax balances, from which the model derives the return to investors and the associated income tax obligation. Finally, the model sums pass-through expenses, return

to investors, and income tax to arrive at the annual revenue requirement. For a detailed explanation of the model, please refer to Exhibit PIRG 1.3: Investment Depreciation Model Methodology.

Q: Please describe your analysis.

A: I used the Investment Depreciation Model to calculate the incremental revenue requirements associated with two capital investment scenarios. Unless otherwise noted, all model inputs reflect PGL's proposed values in this proceeding. Using these input values, I developed annual capital expenditure forecasts for the two scenarios described below and calculated the revenue requirement for each scenario.

Q: Please describe Scenario One.

A: The first scenario is PGL's proposed PRP. In this scenario, PGL replaces all remaining cast iron and ductile iron pipes less than 36" on its system by 2035. I developed the investment forecast for this scenario using PGL's planned retirement mileage and expenditures from 2026 through 2029. I calculated an average unit cost for PRP investment per mile retired from 2027, which equates to roughly $6.2 million per mile retired, and used this unit cost and PGL's planned retirement mileage to project annual expenditures from 2030 through 2034. Note that PGL's proposed PRP costs include replacement of CI/DI services as well as mains. However, there are only 230 CI/DI services on PGL's system according to 2024 PHMSA data, equating to roughly 2 miles of services, which is a small fraction of the 1,020 miles of CI/DI mains. For purposes of this analysis, I include the cost of services in our unit cost of main replacement. Investments in this scenario are depreciated over 67 years,

assuming straight line depreciation, and a net salvage rate equivalent to 100 percent of the upfront cost of the asset.

Q: Why did you use 2027 as the basis for calculating a replacement unit cost?

A: PGL reduced its planned retirement mileage for 2026 from 35 miles to 21 miles, and reduced its proposed expenditures from $214 million to $210 million.[17] The unit cost of replacement for 2026 based on the original values was $6 million per mile retired; however, the unit cost increased to $10 million per mile retired with the updated values. The unit cost of replacement based on PGL's proposed 2027 values is $6.5 million. PGL projects expenditure and retirement mileage for 2028 and 2029 as well; however, PGL has not developed the same detailed cost estimates for 2028 and 2029 projects as it has for 2026 and 2027. Therefore, I find it reasonable to use 2027 unit costs as the basis for projecting PRP replacement expenditure for years 2030 through 2034.

Q: Please describe Scenario Two.

A: The second scenario assumes PGL replaces the remaining cast iron and ductile iron pipes less than or equal to 8" in diameter on its system, and reconditions the remaining CI/DI mains greater than 8" in diameter and less than 36" using CIPL technology, all by 2035. To determine the mileage of CI/DI pipe to replace versus reline, I used 2024 Pipeline and Hazardous Materials Safety Administration ("PHMSA") data showing pipe mileage by material and diameter reported by PGL.[18] Note that PHMSA reports cast iron and wrought

[17] NSG-PGL Ex. 3.0 REV SUPP02 at 4.
[18] U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration, Gas Distribution Annual Data, available at: https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

iron pipe together as one category; however, PGL does not indicate in its filing that it has any wrought iron pipes on its system,[19] so it is reasonable to assume that the PHMSA data for PGL reflects cast iron pipes only. I estimate that there are roughly 290 miles of CI/DI pipe between 8" and 36" in diameter, based on 2024 PHMSA data and PGL's more recent CI/DI mileage reported by PGL witnesses Eldringhoff and Dickson.[20]

To develop a forecast of annual relining expenditures for Scenario Two, I used publicly available unit costs for relining pipes of different diameters from Progressive Pipe Management ("PPM"),[21] a relining contractor. PPM reports the unit cost of relining pipes from 4" to 48" in diameter (Figure 1). I calculated that the average unit cost for relining pipes >8" to 12" in diameter is roughly $2.0 million per mile, and relining pipes >12" to 36" in diameter costs $3.2 million per mile. I forecasted replacement expenditures using the same approach described for Scenario One.

[19] NSG-PGL Ex. 3.0 REV at 22.
[20] *Id.*
[21] Progressive Pipe Management (PPM), CIPL FAQ, accessed April 25, 2026, available at: https://www.progressivepipe.com/cipl-faq.

Figure 1. Progressive Pipe Management CIPL unit costs

Starline CIPL Installed Price Estimate	
Diameter	Total Price Per Foot
4"	$276.14
8"	$333.50
10"	$356.37
12"	$397.94
16"	$459.99
20"	$515.82
24"	$617.97
30"	$808.16
36"	$945.34
40"	$1,062.27
42"	$1,122.80
48"	$1,235.08

Source: Progressive Pipe Management (PPM), CIPL FAQ, accessed May 4, 2026, available at: https://www.progressivepipe.com/cipl-faq.

Q: Why is it appropriate to reline pipes greater than 8" in diameter?

A: As PIRG witness Lewnard describes in detail, the predominant risks that lead to PHMSA-reportable incidents for CI/DI pipes are ground movement and excavation damage.[22] Ground movement can cause pipes to crack. However, research shows that larger diameter pipes are less susceptible to cracking compared to smaller diameter pipes.[23]

[22] Direct Testimony of Jack Lewnard, PIRG Ex. 3.0.
[23] Operations Technology Development, Guidelines for Cast-Iron Piping Winter Operations, 2014, available at: https://www.otd.org/wp-content/uploads/2021/05/512o-Guidelines-for-Cast-Iron-Piping-Winter-Operations-Summary-2pager.pdf.

Thus, relining is a solution that PGL can review and evaluate to rehabilitate large diameter pipes that are considered less susceptible to cracking. Relining is the basis of the alternative scenario I modeled to be compared to PGL's proposed PRP program.

Q: Please summarize your assumptions for Scenarios One and Two.

A: Scenario One assumes all CI/DI is replaced as proposed in the PRP; Scenario Two assumes CI/DI pipes between 8"-36" in diameter are relined and pipes 8" in diameter and smaller are replaced. Table 2 shows the miles of existing CI/DI pipe addressed through replacement or relining for each scenario and Table 3 shows the projected capital expenditures by scenario. Table 4 provides financial assumptions and other assumptions used in both scenarios. For the purpose of this analysis, relining is treated as a capital expense consistent with PGL's treatment of relining costs.[24] CIPL can extend the life of a pipe 50 years,[25] and is thus depreciated over 50 years in this analysis. The cost of removal for a relined pipe is assumed to be the same as that of a replaced pipe; therefore I use a net salvage rate equivalent to 68 percent of the upfront cost of replacing the pipe. This rate is lower than the net salvage rate for a new pipe because of the shorter book life of relined pipes.

Table 2. Retirement mileage by method and scenario

	Scenario One	**Scenario Two**
Replace	1,020	730
Reline	n/a	290

[24] PIRG Ex. 1.2 (PGL Response to PIRG DR 7.18) at 6-7.
[25] REPAIR Testing & Analysis Team. December 2024. Service Life Assessment of Internal Replacement Pipe: External Load Testing of I-Main™, (Final Report 1.0), available at: https://www.colorado.edu/center/ciest/IMain-Testing-Report.

Table 3. Annual capital expenditures by scenario

	2026	2027	2028	2029	2030	2031	2032	2033	2034
Scenario One ($M nominal)	$210	$344	$532	$537	$1,023	$1,047	$1,072	$1,097	$489
Scenario Two ($M nominal)	$167	$290	$504	$511	$862	$882	$903	$924	$411

Table 4. Financial and other assumptions

Metric	Value
Capital structure	42.94% long-term debt, 3.06% short-term debt, 54% equity
Cost of debt	3.71% (long-term debt), 5.09% (short-term debt)
Cost of equity	10.1%
Federal tax rate	21.0%
State tax rate	9.5%
Property tax rate	0.067%
Tax life	20 years
Book life of plastic mains	67 years
Net salvage rate of plastic mains	-100%
Book life of relined mains	50 years
Net salvage rate of relined mains	-68%

Q: How are the cost estimates in Scenario Two conservative?

A: Scenario Two is designed to be conservative. That is, the modeling assumptions result in high capital expenditure costs and high rate impacts, thus resulting in a conservative estimate of savings. The upfront cost and revenue requirement of Scenario Two are likely conservative because of how I treat the cost of removal for relined pipes. Relined pipes in Scenario Two include the full cost of removal as if the pipe had been newly replaced. However, the cost of removal of the existing CI/DI pipes that are relined in Scenario Two has already been accounted for in the depreciation of the existing pipes. Therefore, Scenario Two is likely double counting the cost to remove to same pipe. Additionally,

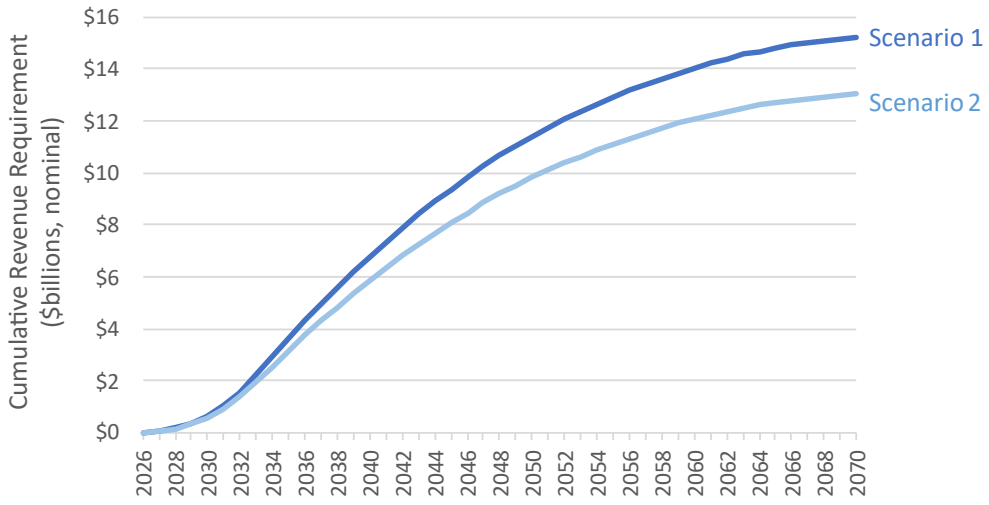
relining does not require the same level of construction as pipe replacement. The avoided cost of public disruptions, lost business, and other community impacts are not reflected in Scenario Two.

B. Findings

Q: Summarize the findings from your analysis.

A: The results of my analysis show that Scenario Two is associated with a lower incremental revenue requirement than Scenario One, suggesting that Scenario Two would translate into reduced costs for ratepayers both in the near term and over the useful life of the asset. Under Scenario One, PGL will invest $5.5 billion (in 2025 dollars) from 2026 through 2034, compared to only $4.8 billion under Scenario Two. Initial investment costs in Scenario Two are lower as a result of the lower cost of relining compared to pipe replacement. The cumulative revenue requirement under Scenario One is $1.6 billion greater than Scenario Two by 2050 and $2.2 billion greater by 2070, as shown in Figure 2.

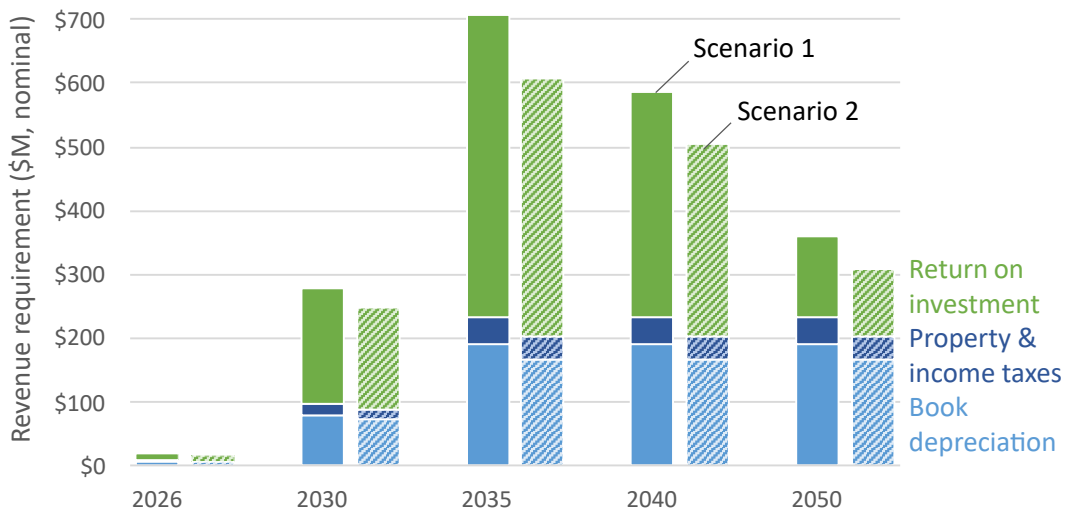
Figure 2. Cumulative revenue requirement by scenario



Q: What are the components of the revenue requirement and how do they change over time?

A: Revenue requirement consists of the following components: book depreciation expense, which recovers the original cost of the investments and the associated cost of removal (return **of** investment), state and federal income taxes, property taxes, and return on the invested capital (return **on** investment). Figure 3 shows a snapshot of the revenue requirement for each scenario in selected years. The book depreciation expense remains the constant throughout the useful life of the investment, as it is calculated on a straight line basis. The return on investment, however, is the greatest in the years directly following the investment and decreases over time as accumulated book depreciation reduces the net plant in service balance, which in turn reduces net rate base, and accumulated deferred income taxes further decrease net rate base (the amount on which the utility earns a return) over time. In 2035, return on investment makes up 67 percent of the total revenue requirement for Scenarios One and Two.

Figure 3. Revenue requirement component breakdown by scenario



Q: What are the implications for ratepayers from each scenario?

A: In the near term, the difference between the two scenarios is modest. In 2026, the rate impact is similar for both scenarios, at $0.01 per therm. This translates to annual bill impacts of $14 and $11 per typical customer for Scenarios One and Two respectively. The divergence between the two scenarios grows substantially over time, as the difference in capital expenditures between the two scenarios grows. By 2035, Scenario One is projected to have a rate impact of $0.60 per therm and an annual bill impact of $581 per typical customer, compared to $0.51 per therm and $500 annual bill impact per typical customer in Scenario Two. Table 5 illustrates the impact for selected years.

Table 5. Rate and bill impacts by scenario

Metric	Scenario	2026	2030	2035	2050
Rate impact ($/therm)	One	$0.01	$0.23	$0.60	$0.30
	Two	$0.01	$0.21	$0.51	$0.26
Annual bill impact ($/customer)	One	$14	$228	$581	$295
	Two	$11	$204	$500	$252

Q: How did you develop rate and bill impacts of the two scenarios?

A: To estimate the rate impact to residential customers from the PRP under each scenario, I first allocated the PRP revenue requirement to the residential class proportional to its share of rate base and book depreciation expense.[26] Dividing this allocated revenue requirement by residential sales volumes for the test year[27] yields an approximate per-therm rate impact for each scenario. To translate this rate impact into a bill impact, I calculated average

[26] NSG-PGL Ex. 10.6P at page 1, lines 19 and 28.
[27] NSG-PGL Ex. 2.1P at 27.

residential customer usage based on EIA Form-176 data, which reports annual residential sales volumes and customers at the utility level.[28] Using this data, I calculated that the average annual consumption for residential PGL customers in 2024 was 973 therms per customer, which I then multiplied by the estimated annual PRP per-therm rate impact to calculate annual bill impacts.

These estimates are high-level approximations used to illustrate the impact of adopting repair technologies when possible in lieu of pipe replacement. These estimates do not account for potential future changes in revenue allocation to the residential class, nor do they account for changes in residential sales or average residential consumption over time. Further, the modeled cost savings to ratepayers under Scenario Two would be much greater if PGL were to consider repairing pipes lower in diameter than the assumed 8"-36" pipes. The systematic adoption of NPAs as an alternative to replacement, as PIRG witnesses Brown and Walsh discuss in their testimonies, also has the potential to lead to further cost savings.

Q: What are the implications of your analysis in a potential future where market trends and climate policies lead to declining gas consumption and a lower customer base?

A: My analysis assumes flat residential sales volume based on test year, which means that the ratepayer impacts identified in my analysis represent a conservative estimate of the potential burden on customers. In a future where climate policies, such as building electrification standards and appliance efficiency requirements, and broader market trends

[28] U.S. Energy Information Administration. Form EIA-176, Type of Operations and Sector Items. Available at: https://www.eia.gov/naturalgas/ngqs/#?report=RP4&year1=2024&year2=2024&company=Name.

lead to a decline in gas consumption, the ratepayer impacts identified in my analysis would likely be materially worse. This is because the revenue requirement associated with the proposed investments must be recovered from a smaller volume of gas consumed, thus leading to a higher per dekatherm rate impact. For this reason, PGL should adopt a more restrained capital expenditure program that incorporates pipe repair in combination with widespread adoption of NPAs, as these measures would mitigate the impact to future ratepayers.

Q: What are the potential implications on stranded costs under each scenario?

A: Stranded costs refer to capital investments made by a utility that are not fully recovered through rates over the useful life of the asset. My analysis shows that in 2050, $2.6 billion of the initial investment plus the cost of removal remain undepreciated under Scenario One, compared with $2.2 billion under Scenario Two. The magnitude of undepreciated assets in 2050 raises concern about stranded costs, particularly with the uncertainty surrounding future gas demand. However, the estimated $400 million difference between the two scenarios represents a materially lower stranded cost risk under Scenario Two.

Q: What do your findings regarding revenue requirements and stranded costs demonstrate?

A: My analysis of Scenario One and Scenario Two demonstrates the benefits of reducing capital expenditures, showing that a more restrained capital investment plan results in meaningfully lower revenue requirements, improved ratepayer affordability, and reduced long-term financial exposure for the utility and its customers. This suggests that the

Commission should encourage PGL to identify opportunities to reduce its proposed PRP spending.

Q: Please describe the extent to which NPAs could further reduce impacts to ratepayers.

A: Implementing NPAs are a way to meaningfully reduce capital expenditures. As set forth by PIRG witness Walsh, the deployment or application of NPAs have the potential to cost-effectively retire CI/DI pipe and thus avoid gas infrastructure investments. While my testimony does not quantify the ratepayer impacts of implementing NPAs, NPAs should be considered within the PRP as widespread adoption of NPAs can support the retirement of CI/DI pipe. By using NPAs to avoid replacing CI/DI pipe with new pipe, NPA can help downsize the pipe system and avoid capital expenditures, which in turn can reduce ratepayers' bills over the long-term.

Consolidated Edison Company of New York has made notable progress in implementing NPAs. As of November 2025, Con Edison had electrified 63 buildings and avoided the installation of nearly 3,000 feet of gas main and associated services.[29] Incorporating NPAs into system planning in this way is essential to prudently managing the system. Yet, as discussed in testimonies of the other PIRG witnesses, PGL has not taken steps to adequately integrate NPAs into its system planning. PGL must consider NPAs as a part of its evaluation of the relative costs of alternatives[30] in order to ensure it is making prudent investments.

[29] Consolidated Edison Company of New York, Inc. Non-Pipes Alternatives Annual Expenditures & Program Report, November 2025, Case 22-G-0065.
[30] Docket Nos. 23-0068 and 23-0069 (cons.), Final Order at 10 (Nov. 16, 2023).

VI. CONCLUSION

Q: Please summarize the findings from your analysis.

A: My analysis demonstrates the significant benefits to ratepayers of a meaningful reduction in capital expenditures. Under PGL's proposed PRP (Scenario One), cumulative revenue requirement reaches $15.2 billion in 2070, compared to the revenue requirement of $13.0 billion associated with an alternative a lower capex scenario where PGL relines larger CI/DI pipe and replaces the smaller pipe (Scenario Two). The typical residential ratepayer under Scenario One would pay an additional $581 annually in 2035, compared to $500 under the lower capital expenditures envisioned in Scenario Two. Notwithstanding this difference, both scenarios carry significant ratepayer impacts. To further reduce the burden on ratepayers, PGL should continue to consider alternatives to pipeline replacement, such as NPAs and other forms of pipeline repair, that may further reduce ratepayer impacts and the risk of stranded assets in the future.

Q: Does this conclude your direct testimony?

A: Yes, it does.