

BEFORE THE  
STATE OF NEW YORK  
PUBLIC SERVICE COMMISSION

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In the Matter of

New York State Electric and Gas Corporation  
Rochester Gas and Electric Corporation

Cases 25-E-0375, 25-G-0378, 25-E-0379 & 25-G-0380

November 7, 2025

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Prepared Redacted Testimony of:

Staff Gas Infrastructure and  
Operations Panel

Andrew Timbrook  
Utility Engineering Specialist 3

Kyle LaBelle  
Utility Analyst 2

David Trost  
Utility Analyst Trainee

Nicolas Brennan  
Utility Analyst Trainee

Spencer Freer  
Excelsior Fellow

Aislynn Schneider  
Utility Engineering Specialist 1

State of New York  
Department of Public Service  
Three Empire State Plaza  
Albany, New York 12223-1350

1 Q. Members of the Staff Gas Infrastructure and  
2 Operation Panel, referred to as the SGIOP or the  
3 Panel, please state your names, employer, and  
4 business address.

5 A. Andrew Timbrook, Kyle LaBelle, David Trost,  
6 Nicholas Brennan, Spencer Freer and Aislynn  
7 Schneider. We are employed by the New York  
8 State Department of Public Service, referred to  
9 as the Department. Our business address is  
10 Three Empire State Plaza, Albany, New York  
11 12223-1350.

12 Q. Mr. Timbrook, what is your position in the  
13 Department?

14 A. I am employed as a Utility Engineering  
15 Specialist 3 in the Gas System Planning and  
16 Reliability Section of the Office of Energy  
17 System Planning and Performance, or OESPP.

18 Q. Please describe your educational background and  
19 professional experience.

20 A. I received a Bachelor of Science in Civil  
21 Engineering from the University of Pittsburgh in  
22 2010. After graduating from the University of  
23 Pittsburgh, I worked for Hunt Engineers,  
24 Architects and Land Surveyors from 2011 to 2012,

1           where my responsibilities included modeling  
2           municipal water systems and designing utility  
3           systems. In 2012, I joined the Gas and Water  
4           Rates Section of the Department as a Junior  
5           Engineer. In my current role as Utility  
6           Engineering Specialist 3 in OESPP, I review the  
7           gas capital investments and associated operating  
8           expenses included in gas utility rate filings.

9    Q.    Have you previously testified before the  
10          Commission?

11   A.    Yes. I provided testimony in Case 13-W-0295,  
12          United Water New York, Inc., regarding non-  
13          revenue water, which I will refer to as NRW,  
14          sales and revenue forecast, the revenue  
15          reconciliation mechanism, and proposed tariff  
16          changes; Cases 13-W-0539, 13-W-0564, and 14-W-  
17          0006, United Water New Rochelle and United Water  
18          Westchester, regarding rate design, NRW, and  
19          proposed tariff changes; Case 14-G-0494, Orange  
20          and Rockland Utilities, Inc., or O&R, regarding  
21          the embedded cost of service study, revenue  
22          allocation, and rate design; Case 16-W-0130,  
23          Suez Water New York, Inc., regarding rate  
24          design, NRW, and water conservation programs;

1 Case 16-W-0259, New York American Water Company,  
2 Inc., regarding revenue allocation and rate  
3 design; Cases 17-E-0238 and 17-G-0239, Niagara  
4 Mohawk Power Corp. d/b/a National Grid,  
5 regarding investments in Information Services;  
6 Case 17-G-0460, Central Hudson Gas and Electric  
7 Corp., or Central Hudson, regarding investments  
8 in Information Services; Case 18-G-0068, O&R,  
9 regarding depreciation, the sales and revenue  
10 forecast and gas operations and maintenance, or  
11 O&M, expenses; Case 19-G-0066, Consolidated  
12 Edison Company of New York, Inc., regarding gas  
13 capital expenditures; Case 21-G-0577, Liberty  
14 Utilities (St. Lawrence Gas) Corp., or Liberty  
15 SLG, regarding gas capital expenditures and the  
16 plant-in-service model; Cases 23-E-0317, et al.,  
17 New York State Electric & Gas Corporation, or  
18 NYSEG, and Rochester Gas and Electric  
19 Corporation regarding gas capital expenditures,  
20 plant-in-service model, O&M expenses, and net  
21 plant true up; Case 23-W-0235, Liberty Utilities  
22 (New York Water) Corp., regarding capital  
23 expenditures, revenue allocation, rate design  
24 and depreciation; and Cases 24-E-0322 and 24-G-

1           0323, Niagara Mohawk Power Corp. d/b/a National  
2           Grid, regarding gas capital expenditures,  
3           revenue allocation and rate design, and gas  
4           interruptible service options.

5   Q.    Mr. LaBelle, what is your position in the  
6           Department?

7   A.    I am employed as a Utility Analyst 2 in the Gas  
8           System Planning and Reliability Section of  
9           OESPP.

10   Q.   Please describe your educational background and  
11           professional experience.

12   A.    I received a Bachelor of Science degree in  
13           Biomedical Sciences from the State University of  
14           New York Buffalo in 2018. Before my employment  
15           at the Department, I was contracted as a Medical  
16           Device Sales Representative from 2018 to 2022  
17           and provided clinical and sales support for a  
18           portfolio of orthopedic device companies. I  
19           joined the Department in June of 2022 as a  
20           Utility Analyst Trainee in the Office of  
21           Consumer Services. In my current role as a  
22           Utility Analyst 2 in OESPP, I review the gas  
23           capital investments and associated operating  
24           expenses included in gas utility rate filings.

1 Q. Have you previously testified before the  
2 Commission?

3 A. Yes. I have testified in rate proceedings  
4 concerning Central Hudson, in Cases 23-E-0418  
5 and 23-G-0419; The Brooklyn Union Gas Company  
6 d/b/a National Grid NY, or KEDNY, and KeySpan  
7 Gas East Corp. d/b/a National Grid, or KEDLI, in  
8 Cases 23-G-0225 and 23-G-0226; Niagara Mohawk  
9 Power Corporation d/b/a National Grid, or NMPC,  
10 in Cases 24-E-0322 and 24-G-0323. The subjects  
11 of my previous testimonies have included  
12 customer service performance incentives, call  
13 center operations, customer arrears and  
14 uncollectibles, customer information systems,  
15 low-income programs, and customer payment  
16 options.

17 Q. Mr. Brennan, what is your position in the  
18 Department?

19 A. I am a Utility Analyst Trainee in the Gas System  
20 Planning and Reliability section of the  
21 Department's OESPP.

22 Q. Please describe your educational background and  
23 professional experience.

1 A. In 2011, I received a Bachelor of Arts in  
2 English from Fordham University. In 2016, I  
3 received a Master of Arts in British and  
4 American Literature from Hunter College. In  
5 2019, I received a Master of Arts in Early  
6 Modern Studies from the State University of New  
7 York at Albany. I began working for the  
8 Department in November 2023 as a member of the  
9 Gas System Planning and Reliability Section of  
10 the Department's OESPP.

11 Q. Have you previously testified before the  
12 Commission?

13 A. Yes. I submitted testimony in Case 23-G-0627  
14 regarding proposals from National Fuel Gas  
15 Distribution Corporation for research,  
16 development and demonstration and renewable  
17 natural gas, referred to as RNG, projects. I  
18 submitted testimony in Case 24-G-0323 regarding  
19 proposals from the Niagara Mohawk Power  
20 Corporation d/b/a National Grid for non-pipe  
21 alternatives, referred to as NPAs, reliability  
22 projects, RNG interconnections, and energy  
23 transfer stations for the injection of both  
24 compressed natural gas and RNG into the

1 distribution system. Additionally, I submitted  
2 testimony in Case 24-G-0668 regarding proposals  
3 from Liberty SLG for gas system reliability  
4 projects, hybrid heat pump programs, RNG  
5 interconnections, and non-pipe alternatives.

6 Q. Mr. Trost, please state your position at the  
7 Department.

8 A. I am a Utility Analyst Trainee, assigned to the  
9 Gas System Planning and Reliability section of  
10 the OESPP.

11 Q. Please summarize your educational and  
12 professional background.

13 A. I attended Binghamton University and graduated  
14 in December of 2023 with a Bachelor of Science  
15 in Economic Policy Analysis. In the summer of  
16 2023, I worked for the New York State Bridge  
17 Authority as an Executive Intern. I began my  
18 current role with the Department as a Utility  
19 Analyst Trainee in January of 2025. In this  
20 role I review the gas capital requests of  
21 utilities in rate case filings.

22 Q. Have you previously testified before the  
23 Commission?

24 A. Yes. I provided testimony in Case 25-G-0073

1           regarding Consolidated Edison Company of New  
2           York, Inc. on topics related to gas capital  
3           requests, the Company's capital budgeting  
4           process and mandated capital reporting  
5           requirements.

6   Q.   Mr. Freer, please state your position at the  
7           Department.

8   A.   I am an Excelsior Service Fellow working in the  
9           OESPP.

10   Q.   Please summarize your educational and  
11           professional experience.

12   A.   I attended Binghamton University and graduated  
13           in May 2023 with a Bachelor of Arts in  
14           Philosophy, Politics, and Law. I continued my  
15           higher education at Binghamton University and  
16           graduated with a Master of Public Administration  
17           in May 2024. While completing my master's  
18           degree I worked for Binghamton University's  
19           Residential Life program as a graduate  
20           assistant. After graduating in May 2024, I then  
21           began my current Excelsior Service Fellowship  
22           role in September 2024.

23   Q.   Please describe your duties in the OESPP.

1 A. My responsibilities within the office focus on  
2 policy research, evaluation, and development,  
3 and thus far have worked on the topic areas of  
4 alternative fuels, such as Renewable Natural  
5 Gas, Differentiated Gas and Hydrogen, Leak Prone  
6 Pipe, Flexible Interconnections, Large  
7 Electrical-Load Interconnections, and non-pipes  
8 alternatives, referred to as NPAs. I also  
9 assist with process improvements across the  
10 OESPP.

11 Q. Have you previously testified before the  
12 Commission?

13 A. Yes. I provided testimony in Case 25-G-0073  
14 regarding Consolidated Edison Company of New  
15 York, Inc. on topics related to gas capital  
16 expenditures, differentiated natural gas,  
17 renewable natural gas, NPAs, liquified natural  
18 gas, or LNG, and capital reporting.

19 Q. Ms. Schneider, what is your position in the  
20 Department?

21 A. I am employed as a Utility Engineering  
22 Specialist 1 in the Gas System Planning and  
23 Reliability Section of the OESPP.

24 Q. Please describe your educational background and

1 professional experience.

2 A. I received a Bachelor of Science degree in  
3 Mechanical Engineering from Rensselaer  
4 Polytechnic Institute in 2012. After  
5 graduating, I worked for TEAM Systems in Toledo,  
6 Ohio in 2013 as a Process Engineer, where my  
7 responsibilities included various tasks in  
8 effort to optimize the assembly process. I then  
9 worked for Millstone Medical Outsourcing in Fall  
10 River, Massachusetts from 2013 to 2014 as a  
11 Quality Engineer, where my responsibilities  
12 included various tasks to manage and execute  
13 qualifications for medical equipment cleaning  
14 and packaging processes. I worked for Comfortex  
15 Window Fashions in Watervliet from 2014 to 2022  
16 as an Industrial Process Engineer, where my  
17 responsibilities included implementing new and  
18 improving existing fabrication processes. I  
19 then worked for Taconic in Petersburg from 2022  
20 to 2024 as a Process Engineer, where my  
21 responsibilities included overseeing production  
22 trials to validate process changes. Before  
23 joining the Department, I worked for the U.S.  
24 Army Watervliet Arsenal as an Industrial

1 Engineer from 2024 to 2025, where my  
2 responsibilities included process analysis and  
3 collaborating with other departments to make  
4 improvements on manufacturing processes. In  
5 July 2025, I joined the Gas System Planning and  
6 Reliability Section of the Department as Utility  
7 Engineering Specialist 1, where my  
8 responsibilities include reviewing gas capital  
9 investments and operating expenses in gas  
10 utility rate filings.

11 Q. Have you previously testified before the  
12 Commission?

13 A. No.

14 Q. What is the purpose of your testimony in these  
15 proceedings?

16 A. We are testifying regarding the initial  
17 testimony of NYSEG and RG&E, collectively  
18 referred to as the Companies, in these  
19 proceedings. Specifically, our testimony will  
20 include: (1) our recommended adjustments to the  
21 gas capital projects and programs proposed by  
22 the Companies' Gas Capital Expenditures Panel;  
23 (2) a summary of the Companies' gas capital cost  
24 estimating practices; (3) a summary of the

1 Companies' gas capital project and program  
2 prioritization practices; (4) a summary of the  
3 Companies' internal capital planning and  
4 approval process and nomenclature; (5) our  
5 recommendations concerning NPAs; (6) our  
6 recommendations for four projects that the  
7 Companies proposed be amortized and recovered in  
8 construction work in progress, or CWIP; (7) our  
9 recommendations regarding the reasonable level  
10 of operating expenses for the Companies to incur  
11 for specific gas operating programs; (8) our  
12 recommendations relating to the Companies' Long  
13 Term Plan, or LTP, costs included in the rate  
14 filing; (9) our recommendations regarding  
15 certain gas capital and operating full-time  
16 equivalents, or FTEs, proposed by the Companies;  
17 (10) our recommendation regarding a tariff  
18 change for dual fuel requirements for large gas  
19 customers; and (11) our recommendations  
20 regarding several gas supply related proposals  
21 made by the Companies included RNG,  
22 differentiated natural gas, or DNG, and sharing  
23 of various gas supply revenues.

24 Q. Does your testimony include any supporting

1 exhibits?

2 A. Yes. We are sponsoring the following exhibits:

3 Exhibit\_\_(SGIOP-1), which includes the various

4 interrogatory requests and responses that we

5 rely upon in our testimony; Exhibit\_\_(SGIOP-2),

6 which shows a comparison of the Companies'

7 proposed capital budgets and our recommended

8 capital budgets, for each proposed capital

9 project and program for each NYSEG and RG&E;

10 Exhibit\_\_(SGIOP-3), which shows a comparison of

11 the Companies' proposed operating expenses and

12 our recommended operating expenses, for each

13 Company; Exhibit\_\_(SGIOP-4), which lists our

14 recommended FTEs; and Exhibit\_\_(SGIOP-5), which

15 shows our recommended format for Differentiated

16 Natural Gas reporting.

17 Q. What period does your recommendations regarding

18 capital expenditures cover?

19 A. The Companies provided forecast capital

20 expenditures for each project by year from 2025

21 through 2031. We reviewed all proposed capital

22 projects and programs from 2025 through 2031.

23 We provide recommendations in our testimony

24 regarding capital expenditures for calendar

1           years 2025, 2026, and 2027, which are shown in  
2           Exhibit\_\_(SGIOP-2). We are prepared to make  
3           recommendations for calendar years 2028 through  
4           2031, if needed.

5   Q.    What period does your recommendations regarding  
6           operating expenses cover?

7   A.    Our recommendations for operating expenses are  
8           for the Rate Year, which is the 12 months ending  
9           April 30, 2027.

10 Cost Estimating Process

11   Q.    How do the Companies forecast capital costs?

12   A.    For most of the proposed gas capital projects  
13           the Companies use similar historical projects to  
14           forecast costs. The Companies have developed a  
15           Gas Program Database to perform this  
16           calculation. The gas program database is  
17           described throughout Exhibit\_\_(GCE-07). First,  
18           the Companies select similar historical projects  
19           to the proposed project based on several factors  
20           including location and operating division,  
21           diameter and type of main installed, whether the  
22           project is located within a roadway or off-road,  
23           and the general complexity of the project. The  
24           Companies' Gas Program Database uses the inputs

1 included in the Companies' response to DPS-337,  
2 defined as normalization factors, to normalize  
3 the cost of the comparable historical projects  
4 into 2024 costs. Next, the Companies adjust  
5 those costs for the scheduled project year using  
6 the adjustment factors in the response to DPS-  
7 265. Finally, the Companies add costs specific  
8 to the proposed project if certain aspects are  
9 unique from the historical project, such as a  
10 direction drill or other significant complexity.

11 Q. What did the Order Adopting Joint Proposal,  
12 issued October 12, 2023, in Cases 22-E-0317, et  
13 al., referred to as the 2023 Rate Order, in the  
14 Companies' previous rate case stipulate for gas  
15 capital project cost estimating?

16 A. The 2023 Rate Order adopted the terms of the  
17 Joint Proposal filed June 14, 2023, in Cases 22-  
18 E-0317, et al., referred to as the 2023 JP.  
19 Section XXVII Part C of the 2023 JP states that  
20 the Companies should keep detailed records of  
21 calculations and methodologies used to estimate  
22 future gas capital projects from historical  
23 project costs and provide this information in  
24 future rate filings to supporting their cost

1 forecasts.

2 Q. Have the Companies fulfilled that obligation?

3 A. Yes. The Gas Program Database and project  
4 whitepapers provided in Exhibit\_\_ (GCE-07) show  
5 the calculation and methodology used to estimate  
6 future costs, as required by the 2023 Rate  
7 Order.

8 Q. Do you have any recommendations for how the  
9 Companies can further improve their cost  
10 estimating?

11 A. Yes. The Companies should measure actual  
12 capital costs against the forecast capital costs  
13 as projects are completed and build improvements  
14 into the Gas Program Database as needed. It is  
15 important to measure the accuracy of the  
16 Companies' cost estimation process to ensure it  
17 is as accurate as possible and measure its  
18 success.

19 Q. How will you discuss cost estimates throughout  
20 your testimony?

21 A. If the Companies use the Gas Program Database to  
22 forecast a project's costs, we will discuss the  
23 cost estimate for that project only in the event  
24 we recommend changes to the estimate. If the

1 Companies do not use the Gas Program Database to  
2 forecast costs, we will discuss how the  
3 Companies estimate the cost and provide any  
4 recommended adjustments.

5 Prioritization Process

6 Q. Describe the Distribution Integrity Management  
7 Plan, or DIMP.

8 A. The Companies use the DIMP to categorize and  
9 quantify the risk associated with all gas mains  
10 in its distribution systems based on various  
11 risk factors such as age of main, material, and  
12 more.

13 Q. How does this differ from Leak Prone Pipe, or  
14 LPP, prioritization?

15 A. LPP prioritization uses the information in the  
16 DIMP along with leak information to prioritize  
17 the segments of LPP that are deemed highest risk  
18 and should be replaced first.

19 Q. Describe the program the Companies use to  
20 prioritize regulator station replacement work.

21 A. As the Companies explain in Exhibit\_\_ (GCE-9),  
22 they utilize a Health Index within their  
23 Regulator Station Operational Database Program  
24 to objectively categorize and prioritize

1 stations and equipment to be addressed through  
2 the Regulator Station Modernization and  
3 Automation Program. The Regulator Station ODP  
4 ranks every regulator and gate station in  
5 operation. The process is more fully described  
6 in the Companies' response to DPS-779.

7 Capital Planning and Approvals

8 Q. Where do the Companies explain their capital  
9 planning process?

10 A. The testimony of the Investment Planning and  
11 Common Capital Expenditures Panel describes the  
12 Companies' capital planning process, beginning  
13 on page 9.

14 Q. How do the Companies define the various stages  
15 of internal approvals for gas capital projects?

16 A. Project Stages, also referred to as Phases of  
17 the Planning Process in Exhibit\_\_ (IPCC-2),  
18 designate the status of each project or program  
19 in the Companies' capital investment internal  
20 approval process.

21 Q. How many phases are in the Companies' internal  
22 planning process?

23 A. Section 1.5 of Exhibit\_\_ (IPCC-2) describes four  
24 phases; however, the graphic in Section 1.6

1 depicts five phases, with a note that Phase II  
2 currently only applies to Electric.

3 Q. What are the project stages of the Companies'  
4 internal planning process?

5 A. As explained in the Companies' response to DPS-  
6 338, there is IP1 - Origination, IP3 - Financial  
7 and Execution Approval, IP4 - Change Approval,  
8 and IP5 - Project Closure.

9 Q. Summarize the project stage IP1 - Origination.

10 A. IP1 - Origination is the first stage when new  
11 projects or programs are entered into the  
12 Companies' Portfolio Management Tool, and  
13 approval at this stage allows for inclusion in  
14 the Capital Investment Plan but does not approve  
15 funding for the project.

16 Q. Summarize the project stage IP3 - Financial and  
17 Execution Approval.

18 A. IP3 - Financial and Execution Approval is  
19 required before the Companies are authorized to  
20 fund the project or program. There are two  
21 forms of IP3 approval. The first form,  
22 preliminary authorization, allows preliminary  
23 engineering and assessments as well as procuring  
24 materials with long lead times. Full Financial

1 and Execution approval is the second form of IP3  
2 approval, which all projects must receive to  
3 authorize funds for the project cost each year.

4 Q. Summarize project stage IP4 - Change Approval.

5 A. IP4 - Change Approval is required for projects  
6 or programs over \$200,000 in total cost, or for  
7 certain designated changes that occur after the  
8 most recent project stage approval.

9 Q. Summarize project stage IP5 - Project Closure.

10 A. IP5 - Project Closure is required when a project  
11 is complete with no planned future expenses.

12 Q. When summarizing the status of gas capital  
13 projects in your testimony, will you simply  
14 refer to these project stages by name?

15 A. Yes.

16 Capital Projects and Programs

17 Q. Describe how the Companies organize their  
18 capital program.

19 A. As shown in Exhibit\_\_(GCE-2), the Companies  
20 organize their capital projects and programs  
21 into the following categories: (1) Asset  
22 Condition; (2) Mandatory; (3) Modernization; and  
23 (4) Reliability.

24 Q. What types of projects are included in the Asset

1 Condition category?

2 A. The Asset Condition category includes projects  
3 and programs related to the replacement of aged  
4 assets that are at or past their end-of-life  
5 cycle. The Asset Condition category includes  
6 distribution main replacements, gate and  
7 regulator station improvements, as well as  
8 capital tools and equipment for gas operations.

9 Q. What types of projects are included in the  
10 Mandatory category?

11 A. The Companies state that Mandatory projects and  
12 programs are those that fulfill the Companies'  
13 obligation to serve as well as projects related  
14 to alleviating any interference that gas  
15 infrastructure may have with municipalities  
16 highway and road projects.

17 Q. What types of projects are included in the  
18 Modernization category?

19 A. A Modernization project upgrades obsolete or  
20 ineffective technology systems and/or  
21 facilities. These projects typically improve  
22 capabilities to remotely manage areas throughout  
23 a gas system in real-time; subsequently, these  
24 projects normally enhance the speed and

1 efficiency of detection and response measures  
2 for safety and reliability issues across a gas  
3 system such as leaks, insufficient pressure  
4 areas, and segment constraints. These projects  
5 also generally improve system planning and  
6 capacity optimization efforts by increasing the  
7 quantity and quality of data collection from  
8 critical and vulnerable regions of the gas  
9 system.

10 Q. What types of projects are included in the  
11 Reliability category?

12 A. The Reliability projects and programs are those  
13 which are needed primarily for reliability  
14 purposes. Examples of distribution system  
15 issues that are resolved through projects and  
16 programs in the Reliability category are local  
17 distribution constraints, supply side  
18 constraints, low pressure issues, and emergency  
19 response preparedness.

20 Q. How will you present your recommendations?

21 A. We will address each category of gas capital  
22 projects and programs in the order stated  
23 previously, describing any specific projects or  
24 programs that we are recommending changes to and

1 the resulting change to the Companies' proposed  
2 budget or schedule. Our recommended capital  
3 budgets for all projects and programs can be  
4 found in Exhibit\_\_ (SGIOP-2).

5 Asset Condition

6 Q. Describe the Companies' Distribution Main  
7 Replacement Program.

8 A. As described beginning on pages 5 and 76 of  
9 Exhibit\_\_ (GCE-07), the Companies use the  
10 Distribution Main Replacement Program to replace  
11 mains that are not classified as leak prone but  
12 have other asset condition issues, conflict with  
13 new construction, or other identified field  
14 conditions.

15 Q. Why is the Distribution Main Replacement Program  
16 needed?

17 A. In Exhibit\_\_ (GCE-07), the Companies state this  
18 program is needed to improve operational safety  
19 and reliability of the gas system by replacing  
20 infrastructure that is in poor condition.

21 Q. How do the Companies prioritize work for this  
22 program?

23 A. In the response to DPS-927, the Companies state  
24 the Distribution Main Replacement Program is

1 generally reactive in nature and does not follow  
2 a specific prioritization process. The  
3 Companies state that work in this program is  
4 often related to projects within the LPP program  
5 or operational needs such as leak repair or  
6 damage.

7 Q. How do the Companies present capital budgets for  
8 this program?

9 A. The Companies include projects that are less  
10 than \$500,000 total in the program titled "NYSEG  
11 or RG&E Dist Main Replacement" in Exhibit\_\_ (GCE-  
12 07), respectively. The Companies list projects  
13 exceeding \$500,000 total as separate, discrete  
14 projects.

15 Q. How do the Companies estimate costs for the  
16 Distribution Main Replacement Program?

17 A. As stated on page 5 of Exhibit\_\_ (GCE-07), the  
18 Companies based program costs on calendar year  
19 2024 costs, stating that costs from years prior  
20 to 2024 were not used as these costs did not  
21 include impacts related to prevailing wage. The  
22 Companies adjusted the 2024 costs to reflect  
23 future increases to contractor, material and  
24 internal labor costs.

1 Q. What is prevailing wage?

2 A. This refers to the Roadway Excavation and  
3 Quality Assurance Act, or REQAA, which became  
4 effective in September of 2023. This  
5 legislation, referred to as prevailing wage by  
6 the Companies, requires that roadway  
7 construction work performed in the public right-  
8 of-way are subject to prevailing wage  
9 requirements.

10 Q. How many miles of distribution main have the  
11 Companies replaced historically in this program?

12 A. The Companies provided the historical mileage  
13 replaced in their Attachment 1 to the response  
14 to DPS-927. In calendar years 2020 through  
15 2024, NYSEG replaced 6.28, 4.30, 2.73, 3.79, and  
16 4.80 miles, respectively. In calendar years  
17 2020 through 2024, RG&E replaced 3.60, 4.30,  
18 2.46, 4.40 and 3.44 miles, respectively.

19 Q. Are the Companies forecasting an increase to the  
20 mileage of mains to be replaced through this  
21 program?

22 A. In their response to DPS-927, the Companies  
23 state that due to the reactive nature and  
24 association with related programs, they are

1           unable to forecast the anticipated replacements  
2           associated with the Distribution Main  
3           Replacement Program.

4   Q.   Do you have any recommendations concerning the  
5           Distribution Main Replacement Program?

6   A.   Yes.  We recommend using the most recent three-  
7           year period, from 2022 to 2024, to forecast both  
8           the annual mileage of main to be replaced under  
9           this program, and the unit cost per mile of that  
10          replacement, rather than the Companies' method  
11          of using only 2024 costs.  Our analysis shows  
12          that the unit cost is not increasing in 2024 as  
13          compared to 2022 and 2023, therefore the impacts  
14          of prevailing wage do not seem to be impacting  
15          this particular program.  A three-year average  
16          uses more historic data than using only one  
17          year, which reduces the impact of outlying data,  
18          and is therefore a better forecast.

19   Q.   How did you determine your recommended budget  
20          for the program?

21   A.   Based on the Companies' response to DPS-927,  
22          this program has replaced an annual average of  
23          3.8 miles of gas main at NYSEG and 3.4 miles of  
24          gas main at RG&E over the most recent three-year

1 period. To develop an annual budget, we  
2 calculated a historical unit cost using mileage  
3 and cost data from the most recent three-year  
4 period, calendar years 2022 through 2024, and  
5 multiplied by 3.8 miles for NYSEG and 3.4 miles  
6 for RG&E. We then applied the inflation factor  
7 recommended by the Staff Forecasting Panel to  
8 calculate budgets for 2026 and 2027. Our  
9 recommended budgets, shown in Exhibit\_\_ (SGIOP-  
10 2), reflect our inflation adjusted unit costs  
11 multiplied by the three-year average mileage for  
12 each of the Companies.

13 Q. Describe the scope of work performed as part of  
14 the Companies' Regulator Station Modernization  
15 and Automation Program.

16 A. The Regulator Station Modernization and  
17 Automation Program, described beginning on page  
18 36 of the Gas Capital Expenditures testimony,  
19 involves a range of activities to upgrade,  
20 enhance, replace, and improve equipment at  
21 regulator stations. Planned projects completed  
22 through this program are identified one year in  
23 advance. The Companies state that the program  
24 also provides flexibility to address emergent

1 safety-related issues and unforeseen equipment  
2 failures.

3 Q. Why is the Regulator Station Modernization and  
4 Automation Program necessary?

5 A. On page 33 of the Companies' Gas Capital  
6 Expenditures Panel, the Companies state gate and  
7 regulator projects are necessary for the safe,  
8 adequate, continuous, and efficient operation of  
9 the Companies' stations. The Companies further  
10 state that gate and regulator station projects  
11 address obsolete equipment, reduce the potential  
12 for customers outages, aid in maintaining a  
13 safely operating station, and reduce maintenance  
14 costs due to equipment failures.

15 Q. How do the Companies estimate costs for this  
16 program?

17 A. On page 15 of Exhibit\_\_ (GCE-07), the Companies  
18 state that cost estimates for NYSEG were based  
19 on 2025 amounts approved in the 2023 Rate Order.  
20 From 2026 through 2028, NYSEG increased the  
21 quantity of stations to be updated by 15 percent  
22 per year. From 2029 through 2031, NYSEG  
23 forecasts no increase in the number of stations  
24 to be addressed annually. Similar to NYSEG, on

1 page 94 of Exhibit \_\_ (GCE-07), the Companies  
2 state the cost estimates for RG&E were based on  
3 the 2024 amounts approved in 2023 Rate Order.  
4 Both Companies apply adjustments for increases  
5 to contractor, material, and internal labor  
6 costs. The Companies noted that regulator  
7 stations are minimally impacted by prevailing  
8 wage due to their location on private property.

9 Q. How many stations have the Companies addressed  
10 since 2020?

11 A. In the response to DPS-775, the Companies  
12 provided a list of regulator and gate stations  
13 that have been improved historically since 2020.  
14 For calendar years 2020 through 2024, NYSEG  
15 addressed 26, 12, 22, 13, and 18 stations  
16 respectively; RGE addressed 21, 19, 11, 11, and  
17 seven stations, respectively, over the same  
18 period.

19 Q. Did the Companies provide a list of specific  
20 stations that are scheduled to be addressed in  
21 the future?

22 A. As part of their response to DPS-775, the  
23 Companies state they are in the process of  
24 identifying and developing regulator and gate

1 station projects for 2026 and beyond. The  
2 Companies include a list of potential stations  
3 to be addressed in calendar years 2026 and 2027.

4 Q. How do the Companies prioritize work for the  
5 Regulator Station Modernization and Automation  
6 Program?

7 A. As explained in Exhibit\_\_ (GCE-9), the Companies  
8 build a Health Index within their Regulator  
9 Station Operational Database Program to  
10 categorize and prioritize stations and equipment  
11 to be addressed through the Regular Station  
12 Modernization and Automation Capital Program.

13 Q. What criteria do the Companies use to develop  
14 the Health Index?

15 A. According to the Companies, the Health Index  
16 identifies seven categories, including:  
17 Regulation Equipment, Relief Equipment,  
18 Branch/Stack Piping, Station  
19 layout/characteristics, Filter/Strainer,  
20 Structural Conditions, and Site Conditions.  
21 Within each category there are several related  
22 sub-categories where Condition Indicator scores  
23 are recorded. The sub-categories are ranked and  
24 weighted in the order of importance to their

1           impact to overall asset health. The Condition  
2           Indicator scores range from CI-01 to CI-05, with  
3           CI-01 being the best state and CI-05 being the  
4           poorest state. The Condition Indicator score is  
5           converted to a multiplication factor, with CI-01  
6           having a multiplication factor of four and CI-05  
7           having a multiplication factor of zero. The  
8           final sub-category score is determined by  
9           multiplying the sub-category weight by the  
10          corresponding condition indicator multiplication  
11          factor. To arrive at the final category score  
12          or Normalized Health Score, the Companies sum  
13          and normalize sub-category scores against an  
14          ideal or as new score. The Overall Health Index  
15          of a station is determined by summing the  
16          weighted average of the seven Normalized  
17          Category Health Scores. More detail on the  
18          Companies' calculation and an example can be  
19          found in Exhibit\_\_ (GCE-9).

20    Q.    Does the list of executed projects always match  
21          the lowest health ranking scores?

22    A.    Not always. As the Companies state on page 36  
23          of their Gas Capital Expenditures Panel, this  
24          program offers the Companies flexibility to

1 address emergent safety-related issues and  
2 unforeseen equipment failures.

3 Q. Do you have any concerns with the Companies'  
4 Station Health Index?

5 A. No. We find the Companies' Station Health Index  
6 methodology to be a reasonable way to  
7 objectively measure asset condition for its Gate  
8 and Regulator Stations. We note that it is  
9 important for the Companies to have a  
10 prioritization process to ensure that the worst  
11 cases of asset condition deterioration are  
12 addressed first. We also acknowledge and agree  
13 that in addition to the unplanned instances  
14 mentioned earlier, circumstances such as  
15 spreading the workload over various operating  
16 divisions and taking advantage of cost savings  
17 by coordinating with municipal work or other  
18 projects planned by the Companies are  
19 appropriate exceptions to deviate from the  
20 prioritization list.

21 Q. How do the Companies' separate program work from  
22 individual rebuild projects?

23 A. According to the Companies' response to DPS-775,  
24 gate and regulator station projects exceeding

1           \$500,000 are treated as standalone projects.

2   Q.    Do you recommend changes to the Companies' cost  
3           estimate for the Regulator Station Modernization  
4           and Automation Program?

5   A.    Yes.  Our recommended budgets for the program  
6           are shown in Exhibit\_\_(SGIOP-2).  To develop our  
7           budgets, we started by using the most recent  
8           three-year average unit cost, or cost to address  
9           each station, applied the inflation rates  
10          recommended by the Staff Forecasting Panel for  
11          calendar years 2026 and 2027, and then  
12          multiplied those figures by the number of  
13          stations we recommend the Companies address each  
14          year.  We are recommending NYSEG address 18  
15          stations and RG&E address 10 stations annually.

16  Q.    Why are you recommending 18 and 10 stations  
17          annually at NYSEG and RG&E, respectively?

18  A.    These amounts reflect the average number of  
19          stations addressed at each Company over the past  
20          three years.  Our recommendation strikes an  
21          appropriate balance between the volume of work  
22          the Companies have completed historically with  
23          the more aggressive proposal the Companies put  
24          forth, while allowing the Companies to address

1           asset condition concerns to maintain safe and  
2           reliable operations of their systems. We also  
3           argue that our method using the cost per station  
4           is more accurate as it reflects the actual costs  
5           incurred by the Companies from 2022 to 2024,  
6           rather than using the forecast costs that were  
7           included in the 2023 Rate Order. Our  
8           recommended budgets are shown in  
9           Exhibit\_\_ (SGIOP-2).

10    Q.    Do you have any other recommendations for any  
11           Asset Condition projects?

12    A.    Yes, the Companies propose the Vienna Road  
13           Regulator Station project for NYSEG, which is  
14           described beginning on page 19 of Exhibit\_\_ (GCE-  
15           07). This project is scheduled for 2026.

16    Q.    What is your recommendation?

17    A.    We recommend delaying the project by one year to  
18           2027.

19    Q.    What is the reason for this recommended delay?

20    A.    As stated in the Staff Policy Panel's testimony,  
21           the Companies proposed delivery revenue  
22           increases for NYSEG gas of \$88.7 million, or a  
23           38.8 percent increase over the base gas delivery  
24           revenues before the proposed revenue increase.

1 We agree that the proposed project is necessary  
2 and also acknowledge that it was approved in the  
3 2023 Rate Order. However, in light of  
4 affordability concerns and our effort to  
5 alleviate such a large increase to delivery  
6 revenues for ratepayers, we recommend delaying  
7 the project by one year. The Staff Policy Panel  
8 describes our intent to balance affordability  
9 and need with the Companies' ability to provide  
10 safe and adequate service. Our recommendation  
11 to delay this project reflects this approach.

12 Mandatory

13 Q. Does the Companies' Mandatory category of gas  
14 capital programs include costs associated with  
15 adding new customers?

16 A. Yes. The "Dist Mains New Business" and "New  
17 Services" Programs shown in Exhibit\_\_ (GCE-04),  
18 for both NYSEG and RG&E include costs associated  
19 with adding new gas customers. We will refer to  
20 these two programs collectively as Customer  
21 Connections.

22 Q. Why are Customer Connections included in the  
23 Mandatory category of work?

24 A. Title 16 Chapter 230.2 of the Official

1           Compilation of the Codes, Rules, and Regulations  
2           of the State of New York, referred to as Part  
3           230, and Subdivision 4 of Section 31 of the  
4           Public Service Law state that gas corporations  
5           are obligated to fulfill, with limited  
6           exceptions, any application for gas service.

7   Q.   Describe the NYSEG and RG&E New Services  
8        Program.

9   A.   As described on pages 143 and 182 of Exhibit\_\_  
10       (GCE-07), this program installs and extends new  
11       gas service lines to both new commercial and  
12       residential customers in compliance with the  
13       Companies' obligation to serve under Part 230.  
14       This program's scope includes the installation  
15       of the service line, regulator, and meter, as  
16       well as the necessary testing to ensure safe a  
17       reliable operation of the new gas service.

18   Q.   Are there any alternatives to this program?

19   A.   No since the Companies are required, under Part  
20       230 and Public Service Law §31(4), to fulfill  
21       applications for service. However, the  
22       Companies provide prospective customers the  
23       option to electrify in lieu of a gas service  
24       installation, but if the customer chooses gas

1 service, the Companies are obligated to fulfill  
2 this request and provide up to 100 feet of gas  
3 service.

4 Q. What budgets do the Companies propose for this  
5 program?

6 A. NYSEG proposes \$3.02 million and \$2.93 million  
7 in 2026 and 2027, respectively. RG&E proposes  
8 \$2.67 million and \$2.71 million in 2026 and  
9 2027, respectively.

10 Q. Describe the NYSEG and RG&E Dist Mains New  
11 Business Program.

12 A. As described on pages 148 and 174 of  
13 Exhibit\_\_ (GCE-07), this program installs and  
14 extends new gas mains to new customers in  
15 compliance with the Companies' obligation to  
16 serve under Part 230.

17 Q. Are there any alternatives to this program?

18 A. No. Similar to the New Services Program the  
19 Companies inform customers of all alternatives,  
20 including electrification. However, if the  
21 customers select gas service, the Companies are  
22 obligated to provide up to 100 feet of gas main  
23 under Part 230 and Public Service Law §31(4).

24 Q. What do budgets the Companies propose for this

1 program?

2 A. NYSEG proposes \$2.42 million and \$2.38 million  
3 in 2026 and 2027, respectively for the Dist  
4 Mains New Business program. RG&E proposes \$2.29  
5 million and \$2.32 million in 2026 and 2027,  
6 respectively.

7 Q. How did the Companies develop the budgets for  
8 the programs included in Customer Connections?

9 A. The Companies developed the budget for these  
10 programs by applying inflation to the 2024 costs  
11 of a new service installation and main  
12 extension. In developing the budgets for these  
13 programs the Companies maintained the number of  
14 annual new service installations and total  
15 footage of main extensions installed at 2024  
16 levels.

17 Q. Do you agree with the Companies' cost estimate  
18 for the Customer Connections programs?

19 A. No. We do not agree that the Companies properly  
20 accounted for the impact of the All-Electric  
21 Buildings Act in the development of the budget  
22 for the Customer Connections programs.

23 Q. Describe the All-Electric Buildings Act.

24 A. The All-Electric Buildings Act is contained in

1 Part RR of Chapter 56 of the Laws of 2023. This  
2 legislation amended the Energy Law directing  
3 extensive changes to the State Building Code and  
4 State Energy Code. The legislation requires  
5 most new buildings in New York State to be  
6 electric and prohibits the use of fossil fuel  
7 burning equipment for new buildings seven  
8 stories or less, with the exception of  
9 commercial or industrial buildings in excess of  
10 one hundred thousand square feet in conditioned  
11 floor area. This legislation is effective  
12 December 31, 2025, and the exception for  
13 buildings in excess of one hundred thousand  
14 square feet will end December 31, 2028. Among  
15 other exceptions, any building for which a site  
16 plan, tentative map, or vision plan has been  
17 approved by the local planning board, or for  
18 which a building permit has been issued, prior  
19 to these dates will not be subject to this  
20 prohibition.

21 Q. What impact could this legislation have on the  
22 Customer Connections budgets?

23 A. Given that the legislation is new and has  
24 several exemptions, it is difficult for us to

1 determine the exact impact of the Customer  
2 Connections programs in the future. However, we  
3 argue that a reduced cost estimate would be  
4 reasonable, as it is likely that the All-  
5 Electric Buildings Act would decrease the number  
6 of applications for new gas service received by  
7 the Companies after January 1, 2026.

8 Q. How do you recommend adjusting the forecast for  
9 the New Services program?

10 A. We recommend the applying the inflation factor  
11 recommended by the Staff Forecasting Panel to  
12 the 2024 cost per service installation. This  
13 cost per service number was derived by dividing  
14 the Companies' 2024 spending for the New  
15 Services program by the number of new services  
16 installed. This information is included in the  
17 Companies' response to DPS-112. In addition, we  
18 recommend a five percent annual decrease in the  
19 number of services installed from 2024 levels to  
20 account for the impact of the All-Electric  
21 Buildings Act.

22 Q. How do you recommend adjusting the budget for  
23 the Dist Mains New Business program?

24 A. We recommend applying the inflation factor

1 recommended by the Staff Forecasting Panel to  
2 the 2024 cost per foot of main extension. We  
3 derived the cost per foot by dividing the  
4 Companies' 2024 spending for the Dist Mains New  
5 Business program by the installed footage of  
6 main extensions. The Companies provide this  
7 information in their response to DPS-1403,  
8 Attachment 1. In addition, similar to the New  
9 Services program, we recommend a five percent  
10 annual decrease from 2024 levels of the total  
11 length of main extensions to account for the  
12 impact of the All-Electric Buildings Act.

13 Q. What is the resulting impact on the Companies'  
14 budget request for the Customer Connections  
15 programs?

16 A. Our recommended adjustments decrease NYSEG's  
17 request for the New Services program by \$398,000  
18 in 2026 and \$371,000 in 2027 as well as a  
19 reduction of \$472,000 in 2026 and \$481,000 in  
20 2027 for NYSEG's Dist Mains New Business  
21 program. The corresponding adjustment for RG&E  
22 yields a reduction in the New Services budget of  
23 \$480,000 in 2026 and \$581,000 in 2027 and a  
24 reduction in the RG&E Dist Mains New Business

1 Program of \$420,000 in 2026 and \$500,000 in  
2 2027. Our recommended budgets are shown in  
3 Exhibit\_\_ (SGIOP-2).

4 Q. Do you recommend any additional customer  
5 protections?

6 A. Yes. Given the uncertainty of the impacts from  
7 the All-Electric Buildings Act on the Customer  
8 Connections budgets, we recommend a separate  
9 downward only net plant true up for the capital  
10 programs within Customer Connections. This will  
11 reconcile customers to the actual capital costs  
12 of these programs if the Companies spend less  
13 than the forecast capital costs. This  
14 protection is important with the uncertainly of  
15 the impacts from the All-Electric Buildings Act.  
16 If the capital costs of Customer Connections  
17 decrease significantly, this reconciliation  
18 would ensure that customers are reconciled with  
19 actual expenditures.

20 Q. What other projects are included in the  
21 Mandatory category of work?

22 A. The Companies' Mandatory category of work also  
23 includes the NYSEG and RG&E Non-Leak Prone  
24 Service Replacement, which the Companies

1           abbreviated as Non LP Srv Repl, Programs in  
2           Exhibit\_\_ (GCE-07), as well as work related to  
3           government projects.

4   Q.   Describe the Non-Leak Prone Service Replacement  
5           Program.

6   A.   As described on pages 153 and 193 of  
7           Exhibit\_\_ (GCE-07) the Non-Leak Prone Service  
8           Replacement Program includes the costs of either  
9           replacing or tying-over any service associated  
10          with a gas main replacement project for services  
11          that do not qualify as a leak prone service, or  
12          LPS. As described on page 67 of the Capital  
13          Expenditures Panel testimony, the costs for this  
14          program correlate to the LPP program as there  
15          are often sections of non LPP and non LPS that  
16          are replaced in conjunction with LPP.

17   Q.   What do the Companies request for this program?

18   A.   NYSEG requests \$4.75 million and \$4.66 million  
19          in 2026 and 2027, respectively. RG&E requests  
20          \$3.88 million and \$3.94 million in 2026 and  
21          2027, respectively.

22   Q.   How do the Companies forecast the costs for this  
23          program?

24   A.   The Non-Leak Prone Service Replacement Program

1 budgets were developed based on 2024 costs which  
2 the Companies adjusted each year to account for  
3 inflation and increased contract costs.

4 Q. Do you recommend any changes for this program?

5 A. Yes. The Companies' response to DPS-1088 shows  
6 that the Companies do not record the number of  
7 non LPS replaced annually and thus they do not  
8 have the data needed to develop the average cost  
9 for a replacement. We recommend that the  
10 Companies begin recording this information to  
11 improve the cost estimates for this program in  
12 future rate proceedings.

13 Q. Do you recommend any other adjustments to the  
14 Non-Leak Prone Service Replacement Program  
15 budget?

16 A. Yes. The Panel recommends that the inflation  
17 factor recommended by the Staff Forecasting  
18 Panel be applied to the 2024 spending in this  
19 program. Additionally, we recommend the same  
20 proportion as we are recommending the Companies'  
21 LPP program footage be reduced later in our  
22 testimony, given that much of the work completed  
23 in this program is completed in tandem with LPP  
24 work. Using this proportion leads to a

1 reduction of 28 percent and 70 percent for the  
2 NYSEG and RG&E Non-Leak Prone Service  
3 Replacement Programs, respectively. Our  
4 recommended budget is shown in Exhibit \_\_ (SGIOP-  
5 2).

6 Q. Describe the NYSEG and RG&E Government Jobs and  
7 Large Government Jobs Programs.

8 A. The Governments Jobs Programs are described on  
9 pages 163 and 199 of Exhibit \_\_ (GCE-07) and the  
10 Large Government Jobs programs are described on  
11 pages 168 and 187 of Exhibit \_\_ (GCE-07). These  
12 programs include the costs associated with work  
13 related to municipal projects that impact  
14 Company infrastructure and facilities. The  
15 Companies will also list individual projects  
16 associated with municipal projects if the  
17 municipality provides advanced notice, separate  
18 from the Government Jobs or Large Government  
19 Jobs program budgets. An example of this is  
20 RG&E's proposed funding for work related to the  
21 Rt 15 Corridor Safety Enhancement project in  
22 2027.

23 Q. What differentiates the Government Jobs and  
24 Large Government Jobs Programs?

1 A. According to page 55 of the Companies' Gas  
2 Capital Expenditures Panel Testimony the  
3 Government Jobs program is reserved for small  
4 projects, defined as projects that cost under  
5 \$750,000. The Large Government Jobs Program  
6 focuses on larger, more complex roadway projects  
7 that have a cost over \$750,000 and that have a  
8 more significant impact on the Companies' gas  
9 systems.

10 Q. What are the Companies' forecast capital costs  
11 for both the Government Jobs and Large  
12 Government Jobs programs?

13 A. NYSEG forecasts \$1.64 and \$1.76 million for the  
14 Government Jobs Program in addition to \$1 and  
15 \$1.1 million for the Large Government Jobs  
16 Programs in 2026 and 2027 respectively. RG&E  
17 forecasts \$1.73 and \$1.92 million for the  
18 Government Jobs Program in addition to \$2.53 and  
19 \$2.82 million for the Large Government Jobs  
20 Programs in 2026 and 2027 respectively.

21 Q. How did the Companies develop the forecast  
22 budgets for the Government Jobs programs?

23 A. The Companies developed the Government Jobs  
24 budget request based on 2024 costs.

1           Specifically, Exhibit\_\_ (GCE-07) states the  
2           Companies used 2024 actual costs as a starting  
3           point because the years prior did not fully  
4           capture the impact of the prevailing wage  
5           requirements imposed by the REQAA. To forecast  
6           costs for 2025 through 2027, the Companies apply  
7           an annual increase in costs from contractor  
8           increases, material increases, and internal  
9           labor costs to 2024 actual costs and a 10  
10          percent increase annually to account for the  
11          potential impacts of the 2021 Infrastructure  
12          Investment and Jobs Act, or IIJA, which the  
13          Companies argue will increase the amount of  
14          municipal work performed.

15    Q.    How did the Companies develop the forecast  
16          budget for the Large Government Jobs programs?

17    A.    The NYSEG Large Government Jobs program budget  
18          request is based on planned costs as there was  
19          no spending under this program in 2024. The  
20          RG&E Large Government Jobs program budget  
21          request is based on 2024 actual costs which  
22          according to the capital variance reports filed  
23          by the Companies in Cases 22-G-0318, et al.,  
24          referred to as Capital Variance Reports, were

1           reallocated to the CM2 Myrtlewood Dr Hwy  
2           Project. Similar to the Government Jobs  
3           program, the Companies adjusted the budgets each  
4           year for inflation and an additional 10 percent  
5           annual increase due to the potential impacts of  
6           the IIJA to forecast costs in 2025 through 2027.

7   Q.   Are planned costs different than actual costs?

8   A.   Yes. Planned costs would be costs that the  
9           Companies forecasted for the program. Actual  
10          costs are costs that have actually been  
11          incurred.

12   Q.   Do you have recommendations regarding the  
13          Government Jobs program?

14   A.   Yes. We acknowledge that the amount of work  
15          performed under the Government Jobs program is  
16          difficult to forecast due to the fact that  
17          municipal project planning is outside the  
18          Companies' control. Given the forecasting  
19          difficulty, we recommend using the most recent  
20          actual spending for Government Jobs program as  
21          included in the most recent Capital Variance  
22          Report filed August 15, 2025, to develop the  
23          forecast 2025 budget for this program.

24          Specifically, we recommend using the 2025 year

1 end spending forecast in the Capital Variance  
2 Report as the 2025 forecast budget for this  
3 program. In addition, we recommend that the  
4 Companies' proposed 10 percent increase in work  
5 related to the IIJA is not supported and  
6 therefore should not be used to forecast costs.  
7 Our recommended budget applies the inflation  
8 factor recommended by the Staff Forecasting  
9 Panel to adjust the 2025 forecast budget to  
10 estimate costs for 2026 and 2027. Our  
11 recommended budgets are shown in  
12 Exhibit\_\_ (SGIOP-2).

13 Q. Do you have any recommendations regarding the  
14 Companies' cost estimate for the Large  
15 Government Jobs Programs?

16 A. Yes. Neither NYSEG nor RG&E had any actual  
17 spending in the Large Government Jobs program  
18 from 2022 through 2024. The Companies' Capital  
19 Variance Report shows zero dollars spent on  
20 Large Government Jobs to date in 2025. The only  
21 spending on a large municipal project from 2022  
22 through 2025 was the emergent CM2 Myrtlewood  
23 project in 2024, which the Companies list as a  
24 separate project from the Government Jobs

1 programs. The Companies are breaking out large  
2 municipal projects into individual projects like  
3 the Rt 15 Corridor Safety Enhancements in 2027  
4 rather than including these in Large Government  
5 Jobs. We recommend that the Companies either  
6 forecast costs for individual projects or for  
7 the Large Government Jobs program, but it is not  
8 reasonable to forecast costs for both.  
9 Therefore, we do not recommend a budget for this  
10 program from 2025 through 2027. We recommend  
11 that the Companies continue to forecast those  
12 types of projects as individual projects and  
13 discontinue the use of Large Government Jobs.

14 Modernization

15 Q. Are the Companies proposing any modernization  
16 projects independent of one another?

17 A. Yes. NYSEG is proposing a Remote Telemetry  
18 Unit, or RTU, Replacement Program, whereas RG&E  
19 is not.

20 Q. What is an RTU?

21 A. An RTU is an in-field micro-processor that links  
22 real-time equipment processes with a Supervisor  
23 Control and Data Acquisition, or SCADA, system  
24 and thereby allows system managers to remotely

1 monitor, measure, and control equipment in  
2 critical system areas.

3 Q. Describe NYSEG's RTU Replacement Program.

4 A. Page 239, of Exhibit\_\_ (GCE-7) from the  
5 Companies' Gas Capital and Expenditures Panel  
6 testimony, states that this program would  
7 replace 83 of the 178 RTUs in operation  
8 throughout the NYSEG divisions. The 83 RTUs  
9 identified for replacement are discontinued  
10 Emerson ROC300-Series models that are no longer  
11 supported by the manufacturer with firmware  
12 updates or replacement parts. NYSEG proposes to  
13 replace these units with new Emerson FB3000  
14 RTUs.

15 Q. Why is NYSEG not proposing to replace the  
16 remaining RTUs?

17 A. The Companies' response to DPS-1102 states that  
18 the remaining units, which are either FloBoss  
19 100 series or ROC800 series, are all in-service,  
20 functional, fully compatible with the SCADA  
21 system, pose no issues to future scalability,  
22 have years of serviceable life remaining, and  
23 are supported by the manufacturer.

24 Q. Why is RG&E not proposing a similar RTU

1 Replacement program?

2 A. The Companies' response to DPS-1102 states that  
3 RG&E does not have any of the obsolete ROC300  
4 units in its gas distribution system.

5 Q. Would this program include other modifications  
6 to RTU communication at the replacement sites?

7 A. This program would also install cellular  
8 communications equipment at these remote sites  
9 and subsequently allow for future retirement of  
10 the landline telephonic equipment on which these  
11 remote sites rely for communication with the  
12 Company's Gas Energy Control Center, or ECC.

13 Q. What is the estimated cost for the program?

14 A. Page 241 of Exhibit\_\_ (GCE-7) states that the  
15 estimated total cost is \$10.604 million, with  
16 spending forecast from 2026 through 2029.

17 Q. How did NYSEG develop the above cost estimates?

18 A. The Companies' response to DPS-415 states that  
19 NYSEG developed these estimates from a vendor  
20 who has experience with RTU replacement. The  
21 Companies affirm that these costs reflect both  
22 historical context, market conditions, and  
23 inflation factors. According to page 241 of  
24 Exhibit\_\_ (GCE-7), the Companies assume that one-

1           third of NYSEG sites will require only RTU  
2           replacement and cellular communication; one-  
3           third of sites will additionally require minimal  
4           to moderate electrical and site upgrades; and  
5           one-third of sites will additionally require  
6           moderate to extensive electrical and site  
7           upgrades.

8    Q.    What is the unit cost for the proposed FB3000  
9           model?

10   A.    The Companies' response to DPS-1102 states that  
11           the estimated unit cost for an FB3000 RTU,  
12           according to a vendor quotation from May 2024,  
13           is between **BEGIN CONFIDENTIAL INFORMATION <**

14           **[REDACTED]** **> END CONFIDENTIAL**  
15           **INFORMATION** depending on site-specific

16           requirements and equipment configuration.

17   Q.    Does NYSEG anticipate operating expense savings  
18           associated with the new units?

19   A.    No, according to the Companies' response to DPS-  
20           415. The Company affirms that maintenance  
21           activities on RTU units are not typically  
22           related to their age.

23   Q.    What are the benefits of replacing the ROC300  
24           units according to the Companies?

1 A. Page 239 of Exhibit\_\_ (GCE-7) states that this  
2 program will improve the reliability,  
3 visibility, and communications for monitoring of  
4 NYSEG's gate and regulator stations, system  
5 pressure endpoints, and areas of low pressure.  
6 If NYSEG does not replace these ROC300 units,  
7 then the Company claims it would eventually risk  
8 system reliability upon equipment failure.

9 Q. How long can the current inventory of RTU  
10 replacement parts support ROC300 units?

11 A. The Companies' response to DPS-1102 states that  
12 they currently have no remaining inventory of  
13 ROC300 units nor any parts for these units.

14 Q. What are the benefits of converting from  
15 landline to cellular communication at the RTU  
16 sites identified for replacement?

17 A. The Companies' response to DPS-415 states that  
18 this conversion would address many of the 121  
19 communication alarms related to ROC300 units  
20 that Gas Control receives on average per day,  
21 many of which relate to failed device  
22 connection. This conversion would ultimately  
23 help to prevent situations that would require  
24 manual operation of RTU sites and, in turn,

1 situations that would disrupt continuous  
2 monitoring of these sites and which could delay  
3 response to an abnormal operating condition as  
4 well as complicate a Gas Controller's ability to  
5 receive, evaluate, and respond to other incoming  
6 safety alarms. NYSEG also affirms that cellular  
7 communications would allow the RTU to  
8 communicate with SCADA on a real time basis  
9 rather than once per hour, which is the current  
10 rate of landline RTU communication. NYSEG  
11 additionally affirms in the response that  
12 cellular communication at certain program sites  
13 could switch between carriers with a dual sim  
14 card in the event of disruption to one carrier,  
15 unlike landline phones, which do not have  
16 alternative communication paths.

17 Q. Describe NYSEG's rationale for selecting the  
18 FB3000 model as the replacement RTU for this  
19 program.

20 A. The Companies' response to DPS-415 states that  
21 NYSEG proposes the FB3000 model because it is  
22 fully supported by the manufacturer, including  
23 technical support, software support and updates,  
24 and the ability to get spare parts and

1 components. Further, the response states the  
2 FB3000 is compatible with the remaining RTUs on  
3 the system.

4 Q. Would the FB3000 model offer enhanced features  
5 relative to the ROC300 model?

6 A. The Companies' response to DPS-415 states that  
7 the FB3000 would offer enhanced safety and  
8 security features; low power consumption; high  
9 surge and short circuit protection; built-in  
10 American Gas Association, or AGA, compliant flow  
11 calculations; and seamless integration with  
12 existing ECC programs.

13 Q. Did NYSEG consider alternative RTU models for  
14 this program?

15 A. The Companies' response to DPS-415 states that  
16 NYSEG did not consider alternative models given  
17 the compatibility of the FB3000 model with the  
18 remaining RTUs and the current SCADA system.

19 Q. Does NYSEG have experience with installing  
20 FB3000 units?

21 A. The Companies' response to DPS-415 indicates  
22 that NYSEG possesses one FB3000 test unit and is  
23 currently bench-testing that unit in a  
24 controlled environment. NYSEG notes that pilot

1 sites have been identified to potentially field  
2 test the FB3000 unit.

3 Q. How would NYSEG determine the order of  
4 replacement?

5 A. NYSEG's response to DPS-415 states that the  
6 Company will likely complete replacements for  
7 this program on a division-by-division basis.  
8 NYSEG arrived at this expectation from a  
9 logistics, mobilization, and cost perspective  
10 according to the wide, non-contiguous geographic  
11 nature of the NYSEG service territories. NYSEG  
12 also aims to prioritize RTUs that have resulted  
13 in higher-than-normal communication alarms and  
14 failures. The Companies' response to DPS-1102  
15 provides a preliminary prioritization plan  
16 developed by the Company's Gas Engineering and  
17 Gas Control. The plan considers factors such as  
18 function and criticality of the facility, with  
19 priority given to Point of Delivery stations,  
20 current communication method, frequency of  
21 trouble calls, and number of remote points  
22 available on a given pressure system. NYSEG  
23 asserts that the Company would determine exact  
24 prioritization during the engineering phase of

1 the program.

2 Q. Does NYSEG have a timeline for completing the  
3 replacements proposed for this program?

4 A. Page 241 of Exhibit\_\_ (GCE-7) includes project  
5 capital costs from 2026 through 2029.

6 Q. What is your recommendation regarding this  
7 program?

8 A. We recommend that NYSEG delay program  
9 expenditures by one year to 2027. We recommend  
10 this delay to provide the Company with  
11 additional time to address opportunities for  
12 improvement of this program's economic  
13 competitiveness and technical feasibility by  
14 considering more than one RTU model with which  
15 to replace its ROC300 units. Further, as of the  
16 time of the Companies' response to DPS-415,  
17 NYSEG had yet to complete bench-testing for its  
18 FB3000 test unit or conduct any field tests for  
19 this RTU model. Therefore, we recommend that  
20 the Company demonstrate economic competitiveness  
21 for the program by issuing request for  
22 proposals, or RFPs, for alternative RTU models  
23 with which to replace ROC300 units and conduct  
24 comparative benefit-cost analyses of replacement

1 RTUs according to these RFPs. We recommend that  
2 the Companies demonstrate the program's  
3 technical feasibility with regards to NYSEG's  
4 gas distribution and SCADA system by completing  
5 its bench-test for its test FB3000 unit as well  
6 as a bench-test for any replacement RTU unit  
7 with a more favorable score relative to the  
8 FB3000 unit according to the benefit-cost  
9 analyses which we recommend above. We also  
10 recommend that NYSEG complete field tests of the  
11 replacement RTU unit with the most favorable  
12 score from the benefit-cost analyses. We  
13 recommend delaying the cost recovery of this  
14 program from 2026 to 2027 to afford NYSEG  
15 adequate time to complete this analysis.

16 Finally, we recommend that RTUs be replaced on  
17 an as-needed basis, when the individual units  
18 fail, in order to maximize the Company's  
19 resource allocation, maximize the useful life of  
20 the existing units, and spread rate impacts over  
21 additional years.

22 Q. What is the Gas Transportation Tracking System,  
23 or GTS?

24 A. The GTS monitors and manages Energy Service

1 Companies, or ESCO, nominations, hourly and  
2 daily usage, capacity releases, usage imbalances  
3 including imbalance cash outs, and ESCO billing  
4 on NYSEG.

5 Q. Describe the Companies' proposed GTS Software  
6 Upgrade Program.

7 A. Page 262 and page 287 of Exhibit\_\_ (GCE-7) state  
8 that this program would develop and implement  
9 software for a new GTS system in an effort to  
10 improve capacity optimization and increase  
11 employee efficiency for both Gas Supply and  
12 Billing and Risk Management. According to the  
13 Companies, the program would ultimately  
14 streamline a process to improve daily  
15 activities, cash outs, billing needs, and month-  
16 end accounting.

17 Q. Why are the Companies proposing an upgrade to  
18 the current GTS?

19 A. The Companies' response to DPS-706 states that  
20 the current software does not provide an  
21 Electronic Data Interchange, or EDI, capability,  
22 which can be provided by other software  
23 developers. The Companies state that this  
24 capability would allow them to provide capacity

1 offerings to a widespread domestic network  
2 outside the current business relationships  
3 within GTS. According to the Companies, the  
4 current GTS only allows the Companies to post  
5 capacity offerings to the bulletin board within  
6 GTS, which only reaches counterparts using the  
7 software. This response also states that  
8 extending these offerings beyond the current GTS  
9 could potentially provide direct impacts to  
10 customer costs. The Companies also state that a  
11 new GTS could reduce time spent by Gas  
12 Transportation Analysts on manual intervention  
13 processes for both daily and month-end  
14 accounting and that new software could perform  
15 the daily process of reconciling ESCO  
16 nominations in the GTS with pipeline bulletin  
17 boards, which can take three analysts up to one  
18 full business day. The Companies claim new  
19 software could potentially save anywhere from  
20 one to 13 business days collectively spent by  
21 analysts on month-end accounting processes per  
22 year and highlight efficiency and optimized  
23 employee hours would be a financial benefit.

24 Q. What is the timeline for this program?

1 A. Page 263 and page 288 of Exhibit\_\_ (GCE-7) state  
2 the Companies are currently in the process of  
3 issuing an RFP to compare costs for a new system  
4 and upgrades to the current GTS. Page 262 and  
5 page 287 of Exhibit\_\_ (GCE-7) further outline the  
6 Companies' proposed initial timeline as follows:  
7 discuss design specifications in 2026, or upon a  
8 Commission order establishing a rate plan in  
9 this proceeding; complete software development  
10 and implementation by the end of 2027; and begin  
11 full usage within Gas Supply in early 2028.  
12 Pages 262 and 287 also note that delays to the  
13 rate proceeding may push some development spend  
14 into the 2028 capital year.

15 Q. What is the useful life of the current GTS  
16 software?

17 A. The useful life of the current GTS software,  
18 which was implemented in 2014, is 20 years as  
19 detailed by the Companies on pages 263 and 288  
20 of Exhibit\_\_ (GCE-7).

21 Q. Have the Companies performed any upgrades to the  
22 current GTS since its inception?

23 A. The Companies' state, in response to DPS-706,  
24 that the developer of the current GTS has

1           executed minor upgrades. The Companies have not  
2           considered major upgrades to the current GTS to  
3           be cost-efficient due to the dated nature of the  
4           current software coding.

5   Q.    What is the estimated cost of the new GTS?

6   A.    Pages 263 and 288 of Exhibit\_\_ (GCE-07) estimate  
7           the combined cost of a new GTS at \$4 million.  
8           The Companies propose allocating the \$1.96  
9           million of the cost to NYSEG and \$2.04 million  
10          to RG&E. Each Company proposes to spend the  
11          entirety of its respective cost for this project  
12          in 2027.

13   Q.    How did the Companies develop this program's  
14          cost estimate?

15   A.    Pages 263 and 288 of Exhibit\_\_ (GCE-7) state that  
16          the Companies applied inflation from 2014 to the  
17          original cost for the current GTS software, or  
18          \$2 million, to arrive at a cost of \$4 million  
19          for a combined new GTS for both NYSEG and RG&E.  
20          The Companies recognize that the basis of this  
21          cost estimation is in its very early stages.

22   Q.    Do the Companies anticipate increased revenues  
23          and subsequent cost savings to customers from  
24          extending capacity offerings beyond counterparts

1 using the current GTS?

2 A. No, the Companies have not provided any  
3 estimates for increased revenues or cost  
4 savings.

5 Q. Have the Companies quantified the financial  
6 benefit of more efficient and optimized employee  
7 hours from this project?

8 A. No.

9 Q. How do the Companies propose to redirect the  
10 time that new software could potentially afford  
11 Gas Transportation analysts?

12 A. The Companies' response to DPS-706 states that  
13 the Companies would use employee hours regained  
14 through the proposed GTS software installation  
15 for cross-training, specifically in the Gas  
16 Supply department, which would allow personnel  
17 to assist in coverage for other  
18 responsibilities, allow organic growth within  
19 the Companies, and improve the knowledge of  
20 employees to continue portfolio optimization and  
21 process improvements.

22 Q. Do the Companies specify any current issues with  
23 coverage in the Gas Transportation, Gas Supply,  
24 or other department?

1 A. No.

2 Q. Do the Companies associate any other benefits  
3 with reduced manual intervention from Gas  
4 Transportation Analysts?

5 A. Pages 262 and 287 of Exhibit\_\_ (GCE-07) state  
6 that streamlining daily and month-end accounting  
7 through new GTS software would reduce the risk  
8 of penalties to the Companies from New York  
9 regulatory commissions.

10 Q. Do the Companies cite any regulatory or legal  
11 issues created by the current GTS software?

12 A. No. The Companies' response to DPS-706 states  
13 that they have not violated any regulatory laws  
14 or incurred any penalty amounts from New York  
15 regulatory entities over the past five years due  
16 to ESCO management issues directly produced by  
17 the current GTS software.

18 Q. Do you have any concerns regarding the  
19 Companies' justification for new GTS software?

20 A. We are concerned that the Companies do not  
21 provide sufficient support for some of the  
22 primary benefits which they associate with new  
23 GTS software. First, the Companies do not  
24 provide support to demonstrate the claimed

1 benefit of capacity optimization through EDI  
2 with either quantified impacts to customers or  
3 direct attestations of savings for customer  
4 bills. Second, there is no demonstration of the  
5 claimed benefit of increased cross-training for  
6 Gas Transportation Analysts, for example with  
7 concrete proposals for such, or with  
8 descriptions of labor insufficiencies in  
9 specific processes or activities. Third, we are  
10 also concerned that the Companies have not  
11 provided support demonstrating the stated  
12 benefit of quantified reduced employee hours for  
13 month-end accounting processes. We note that,  
14 according to the Companies' response to DPS-706,  
15 the potential to save 12 of the 13 business  
16 days' worth of employee hour savings observed by  
17 the Companies in month-end processes depends on  
18 the software Developer being unavailable. This  
19 response does not assign a frequency to the  
20 unavailability of the Developer for these  
21 processes.

22 Q. Do you agree that the Companies have  
23 sufficiently demonstrated the need for new GTS  
24 software?

1 A. No. We note that the current GTS software will  
2 not reach the end of its expected useful  
3 lifetime until 2034. The Companies have not  
4 violated any regulatory requirements over the  
5 past five years due to the current GTS software.  
6 The Companies' response to DPS-706 recognizes  
7 the ability of the Companies to circumvent  
8 manual intervention for certain daily and month-  
9 end processes with software upgrades rather than  
10 installation of a new GTS for \$4 million.

11 Q. What is your recommendation for this program?

12 A. For those reasons, we recommend denying cost  
13 recovery for this program.

14 Reliability

15 Q. Describe the NYSEG and RG&E LPP Replacement  
16 Programs.

17 A. These programs, titled either NYSEG or RG&E Leak  
18 Prone Pipe Replacement Prog - LPP and NYSEG or  
19 RG&E Leak Prone Srv Repl Program, referred to as  
20 the LPP Replacement Program and LPS Replacement  
21 Program, respectively, proactively replace LPP  
22 and LPS on the Companies' gas distribution  
23 systems. Both NYSEG and RG&E propose to  
24 continue replacing 24 miles of LPP annually at

1           each Company, a mileage target that includes  
2           only mains. The Companies state that by  
3           completing 24 miles per year, they will be on  
4           track to eliminate all LPP by the end of 2030.

5    Q.    Are there other capital programs associated with  
6           NYSEG and RG&E LPP Replacement?

7    A.    Yes. The Companies state that the Dist Main  
8           Replacement Asset Condition program and the Non  
9           LP Srv Repl Mandatory program for both NYSEG and  
10          RG&E are associated with the LPP replacement  
11          programs described above. The Companies explain  
12          that they frequently replace sections of non-LPP  
13          and non-LPS along with LPP and LPS where it is  
14          more cost effective than tying into existing  
15          non-LPP and non-LPS. The Companies also replace  
16          a small portion of its LPP through its municipal  
17          highway projects, titled Government Jobs.

18   Q.    Why are these programs needed?

19   A.    These programs remove LPP and LPS from the  
20          Companies' distribution systems, making the  
21          systems safer by reducing the potential for gas  
22          leaks.

23   Q.    How do the Companies present the capital budgets  
24          for these programs?

- 1 A. For LPS, the entire budget is included in the  
2 program titled NYSEG or RG&E Leak Prone Srv Repl  
3 Program. For LPP, the Companies include  
4 projects that are less than \$750,000 total in a  
5 general line titled either NYSEG or RG&E Leak  
6 Prone Pipe Replacement Prog - LPP. For projects  
7 over \$750,000, due to the added complexity of  
8 the larger project, the Companies list those as  
9 separate, discrete projects.
- 10 Q. How do the Companies estimate costs for the LPP  
11 projects in the Leak Prone Pipe Replacement Prog  
12 - LPP category?
- 13 A. The Companies use the 2024 cost per mile and  
14 increases on an annual basis for contractor  
15 increases, material cost increases, and internal  
16 labor increases, as described earlier in the  
17 cost estimation section of our testimony.
- 18 Q. How much of the work under these programs is  
19 completed by contractors?
- 20 A. The Companies' response to DPS-526 provides a  
21 breakdown between mileage replaced by the  
22 Companies and by external contractors. The  
23 majority of LPP replacement is completed by  
24 external contractors.

1 Q. Is that work competitively bid?

2 A. Yes, the Companies state on page 69 of their Gas  
3 Capital Expenditures Panel Testimony that the  
4 individual LPP projects are competitively bid.

5 Q. Have the Companies experienced an increase in  
6 the cost of replacing LPP?

7 A. Yes. The Companies state on page 70 of the Gas  
8 Capital Expenditures Panel testimony that at  
9 NYSEG, the unit cost of LPP replacement has  
10 increased from \$670,000 per mile in 2021 to  
11 \$1.53 million per mile in 2024, and at RG&E  
12 increased from \$560,000 per mile in 2021 to  
13 \$830,000 per mile in 2024. The Company  
14 attributes those increases to the impacts of  
15 REQAA on labor costs, inflation, and increased  
16 costs negotiated in its master service  
17 agreements, or MSAs, with contractors.

18 Q. Do you agree with that conclusion?

19 A. We agree with the conclusion. REQAA would  
20 impact the cost of replacing LPP by increasing  
21 the cost of performing restoration work in a  
22 public right-of-way. However, as we explain  
23 later in our testimony, we forecast a different  
24 cost per mile of replacement of LPP in future

1           years, due to our recommended program changes.

2   Q.   How do the Companies prioritize LPP  
3       replacements?

4   A.   As described previously, the Companies use the  
5       DIMP to identify the risk associated with  
6       various construction practices and materials and  
7       prioritize gas mains for replacement. The  
8       information from DIMP, coupled with leak  
9       information, are used to prioritize the  
10      replacement of all gas main, including LPP.

11   Q.   How do the Companies use the DIMP to score and  
12       weigh the various risk factors to determine  
13       which LPP to replace first?

14   A.   The Companies' response to DPS-526 includes the  
15       LPP database for each NYSEG and RG&E. The LPP  
16       database considers many factors, such as  
17       material type, distances from structure, active  
18       leaks, and whether there is active corrosion,  
19       amongst other considerations.

20   Q.   Do you recommend that the Companies improve on  
21       this prioritization process?

22   A.   No. Given the Companies are nearing the end of  
23       their LPP programs and a thorough prioritization  
24       process is in place, we do not recommend changes

1 to this prioritization process.

2 Q. Are there operating expenses associated with  
3 these programs?

4 A. No. As stated in the project whitepaper on  
5 pages 312 and P371 of Exhibit\_\_(GCE-07), the  
6 Companies have not incurred operating expenses  
7 for either the LPP or LPS replacement programs  
8 since 2021, and do not forecast incurring any  
9 operating expenses through 2031.

10 Q. Do the Companies forecast a decrease in future  
11 operating expenses associated with removing LPP  
12 from its distribution system?

13 A. No. The responses to DPS-526 and DPS-106 state  
14 that while replacing LPP does reduce the  
15 operating expenses associated with leak repairs,  
16 the amount is very small. The Companies state  
17 the majority of the operating expenses for leak  
18 repairs are related to surveys, inspections,  
19 emergency response, third party damage  
20 reduction, meter exchanges, and code related  
21 work that LPP replacement would not impact.

22 Q. Is that reasonable?

23 A. Yes. LPP replacement is important for safety  
24 reasons. However, LPP does not necessarily have

1 active leaks and the Companies correctly state  
2 that the majority of the operating expenses  
3 associated with leak repair are related to  
4 ongoing surveys and programs that would not be  
5 reduced with the replacement of LPP, as those  
6 programs are for all gas main.

7 Q. Do the Companies propose additional FTEs to  
8 manage the LPP and LPS Replacement Programs?

9 A. Yes. According to page 114 of the Gas  
10 Operations Panel testimony, the Companies are  
11 proposing to add three lead engineers at RG&E.  
12 The Company claims these engineers would allow  
13 the Company to reduce its dependency on outside  
14 consultants for its LPP and LPS programs, as  
15 well as the related programs highlighted  
16 previously. RG&E forecasts its LPP program  
17 engineering services costs without these three  
18 FTEs to be \$2.2 million, \$2.2 million, \$2.4  
19 million, \$2.6 million and \$2.7 million from 2026  
20 to 2031, respectively. The Company estimates  
21 that these costs would be reduced to \$1.1  
22 million, \$1.1 million, \$1.1 million, \$1.2  
23 million and \$1.4 million over that same time-  
24 period with these three lead engineers hired at

1 RG&E.

2 Q. Does NYSEG have similar lead engineers employed?

3 A. Yes. The Companies' response to DPS-560 states  
4 that LPP projects are managed by field planners  
5 at NYSEG.

6 Q. What would these three lead engineers cost the  
7 Company in total expenses?

8 A. The response to DPS-560, Attachment 20 shows the  
9 incremental cost for each year from 2026 to  
10 2031. According to that response, the 2026  
11 incremental cost is \$115,412.

12 Q. Do you agree that these three lead engineers are  
13 necessary?

14 A. Yes. If the Company can save \$1.1 million by  
15 hiring these positions for an incremental cost  
16 of \$115,412 then we agree it makes sense to do  
17 so.

18 Q. What is the Company's plan for these positions  
19 once the LPP program is completed?

20 A. As stated in the response to DPS-1116, the  
21 Company would then use these employees for the  
22 replacement of non-traditional LPP, which we  
23 discuss in more detail later in our testimony.  
24 We agree with the Company that hiring these FTEs

1 represents a good opportunity for cost savings.  
2 We also agree that the FTEs have value once the  
3 LPP program is completed.

4 Q. Were NPAs considered instead of the proposed LPP  
5 and LPS replacements?

6 A. Yes. The Companies screen all projects for NPA  
7 suitability and includes a list of LPP projects  
8 in Exhibit\_\_(GCE-12). In 2023, RG&E completed  
9 an NPA project that included three homes and  
10 retired 119 feet of LPP without needed to  
11 replace the pipe.

12 Q. Do the Companies forecast any additional NPAs to  
13 replace LPP or LPS projects?

14 A. The Companies state they will continue to assess  
15 all LPP replacements for NPAs.

16 Q. Do the LPP and LPS replacement programs include  
17 construction work located within a disadvantaged  
18 community?

19 A. Yes.

20 Q. Will these programs disproportionately impact a  
21 disadvantaged community?

22 A. During construction, temporarily. However, the  
23 replacement of LPP and LPS is important to  
24 improve the safety of the gas distribution

1 system. Performing that work withing  
2 disadvantaged communities will improve safety  
3 within that community. Therefore, over the life  
4 of the new gas mains and services, it is overall  
5 beneficial to customers located in disadvantaged  
6 communities to replace LPP and LPS.

7 Q. Do you recommend any changes to the LPP program?

8 A. Yes. The Staff Gas Safety Panel, or SGSP,  
9 discusses what the Companies define as  
10 "traditional" and "non-traditional" LPP. The  
11 SGSP recommends that most non-traditional LPP,  
12 with the potential exception of Aldyl-A pipe,  
13 should not be defined as LPP. However, the SGSP  
14 also notes that the Companies are unable to  
15 quantify the exact amount of Aldyl-A in their  
16 systems and the amount replaced has been  
17 minimal. Therefore, we recommend that what  
18 the Companies term as "non-traditional" LPP  
19 should not be replaced through the LPP program.  
20 Instead, we recommend that the Companies focus  
21 and prioritize the removal of what they define  
22 as "traditional" LPP in the LPP program.

23 Q. How do the Companies define "non-traditional"  
24 LPP?

1 A. The Companies define "non-traditional" LPP as  
2 steel wrapped protected and Aldyl-A gas main, as  
3 shown in their response to DPS-400.

4 Q. Was "non-traditional" LPP, as defined by the  
5 Companies, included in the LPP program mileage  
6 targets in the Companies' prior rate case?

7 A. Yes. The Staff Gas Safety Panel, on page 23 of  
8 its testimony in Cases 22-G-0318 and 22-G-0320,  
9 testified that pre-1971 wrapped steel may be  
10 included in this LPP mileage, provided there is  
11 adequate justification for doing so. The 2023  
12 Rate Order includes a footnote on page 1 of  
13 Appendix L to the Joint Proposal that states  
14 that pre-1971 wrapped steel may be included in  
15 this LPP mileage, provided there is adequate  
16 justification.

17 Q. Did the Companies report a shift in the  
18 replacement of LPP from primarily LPP to  
19 primarily what they define as "non-traditional"  
20 LPP?

21 A. Yes. The Companies' response to DPS-323 shows a  
22 breakdown of the mileage of LPP removed. While  
23 both Companies removed in excess of the 24-mile  
24 annual target, NYSEG in 2023 and 2024 less than

1 33 percent of the LPP removed was actual LPP.

2 At RG&E, that number dropped to four percent in

3 2023 and 14 percent in 2024.

4 Q. Are there instances in which it might be  
5 reasonable to remove what the Companies define  
6 as "non-traditional" LPP in conjunction with  
7 LPP?

8 A. Yes. There could be sections of LPP that  
9 include pipe that is not considered leak prone,  
10 which would include but not be limited to what  
11 the Companies define as "non-traditional" LPP.  
12 We will refer to this pipe as cost effective  
13 non-LPP. In this limited scenario, we recommend  
14 that the Companies continue to remove both LPP  
15 and cost effective non-LPP when it is more cost  
16 effective and practical to do so. The cost of  
17 removing all pipe in those circumstances are  
18 appropriate to be included in the LPP program.

19 Q. As a result of these program changes, how do you  
20 recommend the LPP program budgets be adjusted?

21 A. We recommend that the Companies move forward  
22 with the proposed individual LPP projects and  
23 the LPP program but limit the scope of those  
24 individual projects and LPP program to only LPP

1 and cost effective non-LPP. The Companies'  
2 response to DPS-1043 includes the LPP mileage  
3 included in the proposed individual LPP  
4 projects. Therefore, we calculated a revised  
5 budget by reducing the scope of the proposed  
6 projects to only LPP, using the cost per foot  
7 proposed by the Companies for each individual  
8 LPP project. The remaining LPP mileage that was  
9 not reflected in individual LPP projects was  
10 included in our recommended budget for the LPP  
11 program.

12 Q. Does your budget account for cost effective non-  
13 LPP replacement?

14 A. In their response to DPS-793, the Companies  
15 state they are unable to determine that mileage  
16 of cost effective non-LPP that would need to be  
17 replaced in conjunction with the remaining LPP.  
18 Therefore, we added 10 percent to our  
19 recommended budget to account for any cost  
20 effective non-LPP.

21 Q. How did you determine the unit cost of LPP for  
22 replacement mileage within the LPP program?

23 A. We used the 2024 unit cost of LPP replacement  
24 for pipe within the LPP program and adjusted for

1           inflation in future years.

2    Q.    What mileage targets are associated with those  
3           budget amounts?

4    A.    According to the response to DPS-323, NYSEG has  
5           69 miles and RG&E has 37 miles of LPP remaining  
6           as of the end of 2024.  Conservatively assuming  
7           no replacement of LPP in 2025 to ensure our  
8           recommended funding is sufficient, our  
9           recommended budget uses the remaining 2024  
10          mileage and distributes the remaining mileage  
11          over four years, from 2026 through 2029, which  
12          results in 17.3 miles per year for NYSEG and 9.3  
13          miles per year for RG&E.  Removing the mileage  
14          replaced through the proposed individual LPP  
15          projects results in 17.3 miles in 2026 and 2027  
16          for NYSEG, and 7.3 and 8.1 miles in 2026 and  
17          2027 for RG&E under the LPP program.

18   Q.    What timeframe do you recommend completing the  
19          LPP program?

20   A.    The Companies' response to DPS-793 stated that  
21          the replacement of traditional LPP, as defined  
22          by the Companies, was scheduled to be completed  
23          by the end of 2030, and that due to contractor  
24          availability that could not be done more

1 quickly. However, given we are recommending a  
2 reduction in the mileage of LPP to be replaced  
3 in the program to focus solely on what the  
4 Companies call traditional LPP, contractor  
5 availability should not be as much of a  
6 constraint. We recommend that the Companies  
7 complete the removal of LPP by the end of 2029.  
8 As discussed in the SGSP, we recommend a lower  
9 annual mileage of LPP be replaced to complete  
10 the program by 2029 than the total annual miles  
11 that the Companies propose to complete removal  
12 of LPP by 2030. We note that our recommendation  
13 incorporates conservative estimates for  
14 resources and timing. With the program changes  
15 it is hard to gauge how quickly the Companies  
16 can remove the remaining LPP. The intent of our  
17 recommendation is that the remaining LPP is  
18 removed as quickly as practicable.

19 Q. What impact do these changes have on your  
20 recommended budget for LPS replacements?

21 A. The Companies forecast the costs for this  
22 program using the average number of services per  
23 mile and the LPP program mileage remaining  
24 consistent at 24 miles per year. We recommend

1 adjusting the program to reflect our recommended  
2 LPP mileage targets, using the same method the  
3 Companies used. Our recommended budget is shown  
4 in Exhibit\_\_ (SGIOP-2).

5 Town of Pendleton System Improvement

6 Q. Describe the Town of Pendleton System  
7 Improvement, referred to as the Pendleton  
8 Project.

9 A. The Pendleton Project will construct a new  
10 regulator station in the Town of Pendleton and  
11 install 17,000 feet of six-inch high density  
12 polyethylene, or HDPE, and 2,200 feet of 4-inch  
13 HDPE on RG&E's distribution system in the Town  
14 of Lockport, west of the City of Rochester.

15 Q. Why is the project needed?

16 A. As described by the Companies on page 77 of the  
17 Gas Capital Expenditures Panel testimony, this  
18 project is necessary to address distribution  
19 system constraints. The Companies state that  
20 portions of its 51-pounds per square inch gauge,  
21 or psig, system in Lockport, New York operates  
22 at or below 50 percent of maximum allowable  
23 operating pressure, or MAOP, on a design day.  
24 On a design day, the system endpoints drop to 36

1           percent of MAOP. The Companies attribute this  
2           low pressure to significant growth in  
3           industrial, commercial and residential customers  
4           in the area. The Companies list several  
5           specific examples of customer growth in their  
6           project whitepapers on page 391 of  
7           Exhibit\_\_(GCE-07). The new regulator station  
8           and additional six-inch and four-inch gas mains  
9           would increase system endpoint pressures on a  
10          design day to 32 psig, or to 63 percent of MAOP.

11 Q.    What is the project in-service date?

12 A.    The Companies forecast RG&E will begin  
13          construction in the first half of 2027 and  
14          complete the project in the second half of 2027.

15 Q.    What is the status of internal approvals for the  
16          project?

17 A.    The Companies state it is in the IP3 Financial  
18          Execute approval stage.

19 Q.    Was this project included in a previous rate  
20          filing?

21 A.    No, it was not.

22 Q.    What alternatives were considered for this  
23          project?

24 A.    According to the Companies' Exhibit\_\_(GCE-07) on

1 page 392, RG&E considered three alternatives to  
2 the selected proposal. The first was to install  
3 the proposed six-inch and four-inch gas mains  
4 but not construct the new regulator station.  
5 The Companies state they did not select this  
6 alternative because the southwest quadrant of  
7 the Lockport system would be dependent on only  
8 one regulator station and the new regulator  
9 station would also provide an additional 2.5  
10 psig pressure increase.

11 Q. Is it typical in RG&E's distribution system to  
12 have portions that depend on only one regulator  
13 station?

14 A. According to their response to DPS-538, the  
15 Companies state that it is not uncommon for  
16 entire distribution systems to rely on only one  
17 district regulator station.

18 Q. Could the Company bring the design day pressures  
19 above 50 percent of MAOP without constructing  
20 the new regulator station?

21 A. Yes. The confidential Attachment 5 to the  
22 Companies' response to DPS-538 shows the system  
23 endpoint pressure on a design day for this  
24 alternative is **BEGIN CONFIDENTIAL INFORMATION**

1                   < [REDACTED] [REDACTED] > END

2                   **CONFIDENTIAL INFORMATION**

3           Q.     What is the cost of this alternative?

4           A.     As provided in the response to DPS-628, this  
5                   alternative would cost \$4.4 million.

6           Q.     How does this compare to the cost of the  
7                   proposed project?

8           A.     As updated in the response to DPS-1076, the cost  
9                   stated in Exhibit\_\_ (GCE-07) of \$3.9 million was  
10                  incorrect and excluded the cost of the new  
11                  regulator station. The corrected cost of the  
12                  proposed project is \$5.4 million, including an  
13                  additional \$1.5 million for the new regulator  
14                  station.

15          Q.     Describe the second alternative.

16          A.     The second alternative was to construct the new  
17                  regulator station and install the four-inch main  
18                  but instead of installing 17,000 feet of six-  
19                  inch HDPE, the Company would install 16,000 feet  
20                  of eight-inch HDPE. The Companies state this  
21                  alternative was not selected because the eight-  
22                  inch pipe would not increase system pressure  
23                  more than the six-inch pipe would. The Company  
24                  also states that this alternative would not

1           replace any LPP.

2    Q.    Did the Company model the eight-inch pipe and  
3           the six-inch pipe options to make this  
4           determination?

5    A.    Yes.  According to the Companies' response to  
6           DPS-538, Attachment 6, **BEGIN CONFIDENTIAL**

7           **INFORMATION** < [REDACTED]  
8           [REDACTED] > **END**  
9           **CONFIDENTIAL INFORMATION**

10   Q.    Would the selected project replace LPP?

11   A.    No, it would not.

12   Q.    How much would the second alternative cost?

13   A.    As provided in the response to DPS-628, this  
14           alternative would cost \$5.8 million.

15   Q.    Describe the third alternative.

16   A.    This alternative would construct the new  
17           regulator station but only install 5,400 feet of  
18           four-inch HDPE and the 2,200 feet of four-inch  
19           HDPE proposed in the selected project.  The  
20           Company states that this alternative would only  
21           increase system pressures on a design day from  
22           42 percent to 52 percent of MAOP, with a risk of  
23           dropping below 50 percent within a few years,  
24           and therefore it was not selected.

1 Q. What is the cost of the third alternative?

2 A. As provided in the response to DPS-628, this  
3 alternative would cost \$1.4 million.

4 Q. Do you agree that the Company selected the best  
5 alternative for this project?

6 A. No. We recommend the first alternative,  
7 installing the proposed six-inch and four-inch  
8 gas mains but not constructing the new regulator  
9 station, as the best alternative. This scope of  
10 work would still improve system endpoint  
11 pressure to well above 50 percent of MAOP on a  
12 design day, **BEGIN CONFIDENTIAL INFORMATION** < [REDACTED]

13 [REDACTED]

14 [REDACTED] >

15 **END CONFIDENTIAL INFORMATION.** As the Companies  
16 state in their response to DPS-538, it is not  
17 uncommon for distribution systems to rely only  
18 on one regulator station and constructing a  
19 regulator station to boost pressures by **BEGIN**  
20 **CONFIDENTIAL INFORMATION** < [REDACTED]

21 [REDACTED] > **END CONFIDENTIAL INFORMATION**

22 is not absolutely necessary. Therefore, that  
23 reason for selecting the proposed project is not  
24 valid. The first alternative includes capital

1 cost of \$4.4 million, as shown in  
2 Exhibit\_\_ (SGIOP-2).

3 Q. Does this adjustment impact your recommended  
4 budget for the Regulator Station Modernization  
5 and Automation Program budget?

6 A. Yes. The two budgets are related, as the  
7 Companies separate larger projects that are  
8 above \$750,000, like the Pendleton Project, into  
9 separate capital projects, while smaller  
10 projects are completed within the Regulator  
11 Station Modernization and Automation Program  
12 budget. Therefore, it is likely that as  
13 individual projects are above or below budget,  
14 the Companies adjust the Regulator Station  
15 Modernization and Automation Program budget  
16 accordingly. The Companies' proposed 2027  
17 budget for the Regulator Station Modernization  
18 and Automation Program is \$4.875 million, and  
19 for the Pendleton Project is \$3.884 million, for  
20 a total of \$8.759 million. Assuming that the  
21 Companies would balance budgets between the  
22 Pendleton Project and the Regulator Station  
23 Modernization and Automation Program, the  
24 balanced budgets in 2027 would be \$3.394 million

1           and \$5.365 million for the Regulator Station  
2           Modernization and Automation Program and  
3           Pendleton Project, respectively, with the total  
4           remaining at \$8.759 million. Therefore, we  
5           recommend a Pendleton Project budget of \$4.4  
6           million and adjusted the 2027 Regulator Station  
7           Modernization and Automation Program budget to  
8           \$3.394 million, prior to our recommended changes  
9           to the Regulator Station Modernization and  
10          Automation Program budget described previously,  
11          for a total between the two of \$7.8 million. To  
12          accompany our Pendleton Project adjustment, we  
13          further reduced the Regulator Station  
14          Modernization and Automation Program budget we  
15          recommended earlier by an additional \$1.5  
16          million.

17    Q.    Is it possible to resolve the low system  
18           pressures with an NPA?

19    A.    In the response to DPS-538, the Companies state  
20           that an NPA could potentially resolve or defer  
21           the project and that it plans to solicit for NPA  
22           proposals.

23    Q.    What is the schedule for those solicitations?

24    A.    The response to DPS-538 states that the RFP is

1           scheduled to be issued in September 2025 and  
2           anticipates a bid selection in February 2026.

3   Q.   Has the Company modeled the level of NPA  
4           participation that would be required to resolve  
5           or defer the project?

6   A.   Yes, the Companies state that the reduction on a  
7           design day to avoid the project would be  
8           approximately 110 thousand cubic feet per hour,  
9           or MCFH.

10   Q.   Has the Company engaged stakeholders and  
11           provided notice to the local municipalities  
12           about the project and benefit of an NPA  
13           solution?

14   A.   No. In the response to DPS-538, the Companies  
15           state that RG&E plans to notify stakeholders and  
16           local municipalities about the upcoming RFP  
17           release following the completion of the RFP  
18           process in September 2025.

19   Q.   Do you recommend that RG&E notify stakeholders  
20           and local municipalities sooner?

21   A.   Generally, yes. Stakeholders and local  
22           municipalities can be a resource for the Company  
23           to improve its RFP process. Beyond that,  
24           educating these entities on traditional

1 solutions, costs, and the amount of design day  
2 reduction necessary to avoid these traditional  
3 solutions can be completed well in advance of an  
4 RFP being issued. This can allow an opportunity  
5 for stakeholders and local municipalities to  
6 research and publish additional opportunities  
7 for demand reduction or alternatives to  
8 traditional projects to make the bids for the  
9 RFP more efficient and successful.

10 Q. Is there a specific timeframe prior to a  
11 traditional project being scheduled and RFP  
12 being released that stakeholders and local  
13 municipalities should be engaged by the  
14 Companies?

15 A. We hesitate to recommend a specific timeframe  
16 but would advise that as soon as the need for a  
17 traditional pipeline solution to a system or  
18 supply constraint is identified, that the  
19 Companies should be educating stakeholders and  
20 local municipalities at that time.

21 Q. Is this project located within a disadvantaged  
22 community?

23 A. No, it is not.

24 Norwich-DeRuyter Compressor Reliability

1 Q. Describe the Norwich-DeRuyter Compressor  
2 Reliability project, referred to as the Norwich  
3 Compressor Project.

4 A. The Companies describe NYSEG's Norwich  
5 Compressor Project beginning on page 407 of  
6 Exhibit\_\_ (GCE-07). NYSEG currently has one  
7 compressor, referred to as the Existing  
8 Compressor, located in the Town of Norwich at  
9 its Norwich Compressor Station. The Existing  
10 Compressor boosts the pressure on the DeRuyter  
11 Pipeline, a 50-mile pipeline that is the single  
12 source of gas from Norwich to Oneonta and serves  
13 10,100 customers total, with 5,700 of those  
14 customers located in Oneonta. This project  
15 would add a second compressor in the existing  
16 structure at the Norwich Compressor Station,  
17 similar in functionality and capacity to the  
18 Existing Compressor. The existing building can  
19 accommodate the second compressor without  
20 upgrades as it was originally built with a  
21 second compressor bay.

22 Q. Why is the project needed?

23 A. The Companies state that without a second  
24 compressor as a backup, any malfunction with the

1 Existing Compressor would increase the risk of  
2 customer outages, specifically the 5,700  
3 customers in Oneonta that rely on the pressure  
4 increase provided by the Existing Compressor.  
5 The Company also states that replacement parts  
6 for the Existing Compressor may become more  
7 difficult to acquire as it gets older.

8 Q. How often has the Company historically operated  
9 the Existing Compressor?

10 A. The Companies provided historical maintenance  
11 and operating dates in their response to DPS-  
12 581. Over the most recent five winter periods,  
13 NYSEG has operated the Existing Compressor for  
14 reliability or maintenance purposes on average  
15 10 times per winter. However, it varies  
16 greatly; in the winter of 2022 to 2023, the  
17 Company operated the Existing Compressor twice  
18 for maintenance and zero times for reliability.  
19 During the winter of 2021 to 2022, the Company  
20 operated the Existing Compressor five times for  
21 maintenance and 11 times for reliability.

22 Q. Are there maintenance concerns with operating  
23 this type of equipment infrequently?

1 A. The Company lists potential maintenance concerns  
2 as internal corrosion, oil degradation leading  
3 to wear and tear, internal seal degradation and  
4 potential electrical control system  
5 malfunctions.

6 Q. Would these maintenance concerns be worse with  
7 two units operating even less frequently?

8 A. Yes, it is unclear how this would not be the  
9 case. In the response to DPS-581, the Company  
10 indicates that adds a second compressor and the  
11 resulting infrequent use of either compressor  
12 does not necessarily result in increased  
13 equipment maintenance and reports, as long as  
14 regular, proactive maintenance is performed.

15 Q. Has the Existing Compressor ever experienced a  
16 malfunction and been unable to operate when  
17 needed?

18 A. As shown in the response to DPS-581, on January  
19 29, 2021, the Existing Compressor experienced a  
20 component failure and was repaired the same day.  
21 The Existing Compressor was needed for peak load  
22 conditions on January 30 and 31, 2021 and was  
23 able to be repaired in time for operation.

1 Q. Without a second unit, what could the Company do  
2 operationally to avoid customer outages if the  
3 Existing Compressor was unable to function when  
4 needed?

5 A. As stated in the response to DPS-581, the  
6 Company would seek voluntary load reduction as  
7 well as make use of its interruptible customers  
8 to reduce peak day load. In addition, the  
9 Company can bypass downstream regulator stations  
10 to maintain system pressures.

11 Q. How much notice is typically provided prior a  
12 cold weather event that would require the  
13 Existing Compressor to be used?

14 A. According to the response to DPS-581, typically  
15 two to three days' notice is provided. Under an  
16 emergency basis, the Company estimates it can  
17 make the Existing Compressor operational within  
18 two hours' notice.

19 Q. How often did the Company need to perform last  
20 minute fixes during this time period to get the  
21 existing compressor operational?

22 A. The Company was not able to specify how late  
23 repairs were made but provided a list of 19

1 repairs made to the Existing Compressor since  
2 2020.

3 Q. What is the project in-service date?

4 A. The Company proposes to begin construction in  
5 the first half of 2027 and have the proposed  
6 second compressor operational in the third  
7 quarter of 2027.

8 Q. What is the status of internal approvals for the  
9 project?

10 A. The project is in the IP1 Originate project  
11 approval stage.

12 Q. How was the project cost of \$5.355 million  
13 developed?

14 A. The Company used the cost of installing the  
15 Existing Compressor in 2007, updated for  
16 inflation and based on conversations with  
17 contractors with experience from the original  
18 installation.

19 Q. Has the Company selected a supplier for the  
20 proposed Compressor?

21 A. According to the response to DPS-581, the  
22 Company has not yet selected a supplier.

23 Q. Was this project included in a previous rate  
24 filing?

1 A. No.

2 Q. Are there any FTEs associated with this project?

3 A. No.

4 Q. What alternatives were considered for this  
5 project, including NPAs or potential demand  
6 response?

7 A. The Company considered both certified natural  
8 gas, or CNG, and LNG injections on a peak day to  
9 meet the additional demand and maintain system  
10 pressures. However, the response to DPS-581  
11 states that the large demand on a peak day of  
12 475 MCFH would require at least nine LNG trucks  
13 or 21 CNG trucks, which the Company states would  
14 be operationally impractical.

15 Q. Does the pipeline served by the Existing  
16 Compressor provide gas service to disadvantaged  
17 communities?

18 A. Yes, it does.

19 Q. How many of the 5,700 customers served by that  
20 pipeline are in a disadvantaged community?

21 A. The Company estimates that of those 5,700  
22 customers, 1,421 customers are located in a  
23 disadvantaged community.

24 Q. Is the Norwich Compressor Station located in a

1           disadvantaged community?

2   A.    The Norwich Compressor Station is not located in  
3           a disadvantaged community.

4   Q.    Will installation of a second compressor  
5           disproportionally impact a disadvantaged  
6           community?

7   A.    No.   The additional compressor would be  
8           installed in the Norwich Compressor Station,  
9           which is not located within a disadvantaged  
10          community.

11   Q.    Do you agree that the project is necessary?

12   A.    No.   The Companies claim that infrequent use of  
13          the Existing Compressor can lead to maintenance  
14          issues and possible inoperability and also  
15          indicate that as the Existing Compressor ages,  
16          replacement parts may become difficult to find.  
17          However, the Companies also state that with a  
18          second compressor, proactive maintenance would  
19          alleviate those concerns.   We disagree.   A  
20          second compressor unit would just exacerbate the  
21          existing concern of infrequent operation because  
22          adding a compressor would result in operating  
23          each unit even more infrequently.   While  
24          replacement parts may become more difficult to

1 find, the Company has provided no evidence that  
2 they are currently difficult to procure and has  
3 been able to successfully complete repairs 19  
4 times in the past five years. Finally, the  
5 Company has had the Existing Compressor in  
6 operation since early 2007. The Existing  
7 Compressor is less than 20 years old and has not  
8 had an operational failure in the most recent  
9 five winters. The Company has indicated other  
10 operational solutions, such as demand reduction  
11 through interruptible customers and voluntary  
12 interruptions, as well as bypassing downstream  
13 regulator stations, which would alleviate  
14 reliability issues should the Existing  
15 Compressor fail to become operational.

16 Q. What do you recommend?

17 A. We disagree that a second compressor is the best  
18 solution to the Company's reliability concerns  
19 with the Existing Compressor. We recommend that  
20 the Company continue to perform proactive  
21 maintenance on the Existing Compressor to  
22 ameliorate operational concerns. Also, we  
23 recommend the Company further examine both the  
24 operational solutions we mentioned while

1 exploring any other potentially available  
2 solutions.

3 Goshen System Semi-Perm Peaking Tap

4 Q. Describe the Goshen System Semi-Perm Peaking Tap  
5 project, referred to as the Goshen Peaking Tap  
6 Project.

7 A. This project, as described beginning on page 416  
8 of Exhibit\_\_ (GCE-07), is located in NYSEG's  
9 Goshen territory and includes the construction  
10 of a semi-permanent LNG injection tap. The  
11 injection site will include a meter and  
12 regulator located inside a building, gas  
13 odorization equipment, overpressure protection,  
14 a connection point to an LNG vaporizer outlet,  
15 an area for two to three tractor trailers  
16 carrying LNG to park and inject, physical  
17 security measures such as SCADA, lighting and  
18 fencing, and a generator.

19 Q. Why is the project needed?

20 A. The Companies state that additional supply  
21 sources are limited as its Goshen division is  
22 supplied completely by two other gas utilities:  
23 O&R, and Central Hudson. The Companies point to  
24 customer growth of commercial customers on the

1 Goshen system such as Legoland NY, Amy's  
2 Kitchen, Science of the Soul and the Winery  
3 Warehouse, along with additional residential  
4 development. The Companies state that at its  
5 current design day it is at 68 percent of its  
6 contractual gas supply. The Companies claim  
7 that by adding Amy's Kitchen, which is expected  
8 to add 57 MCFH, on a design day and Winery  
9 Waterhouse, expected to add 83 MCFH on a design  
10 day, NYSEG will cease to have additional gas  
11 supply reserve margin. The LNG injection will  
12 add 100 MCFH on a design day.

13 Q. What is the total contractual gas supply on a  
14 design day currently?

15 A. The response to DPS-686 includes additional  
16 information on the Company's gas supply for its  
17 Goshen distribution system. That response  
18 states that the Company has up to 472.5 MCFH on  
19 a design day, both currently and in the future.

20 Q. What is the current design day demand in MCFH?

21 A. The response to DPS-686 states that the upcoming  
22 2025-2026 winter season has a design day demand  
23 of 433.25 MCFH. For upcoming winter seasons  
24 beyond the upcoming one, that is 424.85 MCFH,

1 not including Amy's Kitchen, the Winery  
2 Warehouse, or any other new customers. The  
3 Companies state that these new loads are not  
4 factored into this forecast until the customer  
5 takes service and the Company can determine the  
6 actual load.

7 Q. When are Amy's Kitchen and the Winery Warehouse  
8 expected to begin taking service?

9 A. The response to DPS-686 provides an update that  
10 the load request for Amy's Kitchen has been  
11 canceled. The response does not provide a date  
12 for the Winery Warehouse to begin taking  
13 service.

14 Q. What time of year is the design day for the  
15 Goshen system?

16 A. Winter.

17 Q. What is Legoland NY's maximum demand in MCFH  
18 during the winter months?

19 A. According to the response to DPS-686, Legoland  
20 NY's maximum demand in winter is 11 MCFH.

21 Q. After adding the Winery Warehouse, what will the  
22 remaining gas supply reserve margin be on a  
23 design day for each year through 2030?

1 A. As stated in the response to DPS-686, based on  
2 the load request, the Companies estimate that  
3 the reserve margin for the upcoming winter,  
4 without the Winery Warehouse, is 317 dekatherms,  
5 or Dths. However, adding Winery Warehouse for  
6 winter 2026-2027, the Companies forecast a  
7 negative reserve margin of 895 Dths, indicating  
8 that on a design day the Company would be  
9 undersupplied.

10 Q. What is the project in-service date?

11 A. The project is scheduled to begin construction  
12 in the first half of 2026 and be completed and  
13 placed in service in the third quarter of 2026.

14 Q. What is the status of internal approvals for the  
15 project?

16 A. The approval stage is IP1 Originate.

17 Q. How was the project cost developed?

18 A. The Companies state the cost was developed based  
19 on conversations with internal personnel that  
20 operate Company-owned LNG peaking facilities and  
21 contractors that did a similar installation in  
22 Walton, New York.

23 Q. What additional documentation did the Company  
24 provide concerning the cost?

1 A. The Companies' response to DPS-686, attachment  
2 1, shows a fully itemized breakdown of the cost  
3 estimate.

4 Q. Was there a competitive bidding process for the  
5 project?

6 A. Yes.

7 Q. What is the status of that bidding process?

8 A. As stated in the response to DPS-686, the site  
9 evaluation has been bid, for which NYSEG  
10 selected the lowest bid. The Company  
11 anticipates bidding the project as well.

12 Q. Do you have any concerns with that estimate?

13 A. Yes, we have concerns that the contingency of 40  
14 percent is too high. While this is a unique  
15 project, the scale is limited and a lot of the  
16 materials needed, such as pipes, fittings,  
17 odorization, and more, are standard. Further,  
18 the project has already partially been bid, and  
19 the cost estimate should not reflect the level  
20 of uncertainty associated with a 40 percent  
21 contingency. Therefore, we recommend that a 20  
22 percent contingency is more appropriate,  
23 reducing the cost from \$3,258,316 to \$2,801,008.

24 Q. Was this project included in a previous rate

1 filing?

2 A. No.

3 Q. Are there any FTEs associated with this project?

4 A. No.

5 Q. What alternatives were considered for this  
6 project, including NPAs?

7 A. Exhibit\_\_ (GCE-07) page 417 describes project  
8 alternatives considered by the Companies. The  
9 Companies state that it considered a CNG  
10 alternative to LNG. However, the Companies  
11 claim the CNG injection site would be much  
12 costlier than an LNG site and an LNG site would  
13 leave fewer stranded costs in the event the  
14 Goshen system demand lowered, and the injection  
15 site was no longer needed.

16 Q. What about NPAs?

17 A. The Companies state in their response to DPS-686  
18 that NYSEG will consider an NPA solution for  
19 this project. The Company has not developed a  
20 schedule for issuing an RFP and has not engaged  
21 stakeholders or local municipalities.

22 Q. Do you have concerns with the progress made  
23 toward developing an NPA solution?

24 A. Yes. The project is scheduled to be completed

1 in 2026. That leaves very little time to engage  
2 stakeholders and local municipalities and  
3 develop a thorough RFP process that will  
4 maximize the potential for successful NPA  
5 solutions.

6 Q. Do you recommend adjusting the project schedule  
7 to accommodate a potential NPA solution?

8 A. Yes. We recommend delaying the project one  
9 year, until 2027, to allow more time for the  
10 Company, stakeholders and the local  
11 municipalities to assess the viability of an NPA  
12 solution.

13 Q. Is this project located within a disadvantaged  
14 community?

15 A. Yes.

16 Q. Is it possible to relocate this project outside  
17 of a disadvantaged community?

18 A. The response to DPS-686 states that it is not  
19 possible to relocate this project outside of a  
20 disadvantaged community due to the relevant  
21 distribution system siting considerations and  
22 hydraulic constraints, as well as the fact that  
23 most of the Goshen distribution system is  
24 located within a disadvantaged community.

1 Q. How will this project impact a disadvantaged  
2 community?

3 A. The Companies state there will be minor  
4 construction impacts limited to a local site.  
5 The completed project will ensure system  
6 reliability on a design day. Operating the  
7 facilities will include truck traffic.

8 Q. How many days per year, on average, would LNG  
9 trucks be injected at the facility?

10 A. According to the Companies' response to DPS-686,  
11 they anticipate between zero and three days per  
12 month from December through March of each  
13 winter, once operational.

14 Q. How many trucks would inject on a design day?

15 A. The Companies estimate that design day  
16 conditions would require three trucks.

17 Q. Will this project disproportionately impact a  
18 disadvantaged community?

19 A. We acknowledge that the truck traffic during  
20 operation of the peaking tap will impact the  
21 local community, which is a disadvantaged  
22 community. However, the Company has justified  
23 the need for the project and there is not a  
24 feasible alternative given the lack of supply

1 options. We recommend the Companies take steps  
2 to attempt to minimize the impact of operating  
3 the facility where possible, and work with the  
4 local community to do so. It is important to  
5 also consider the reliability benefits to the  
6 community as well and the risk that NYSEG not  
7 having adequate supply on a design day poses to  
8 the local community.

9 Pavilion System Semi-Perm Peaking Tap

10 Q. Describe the Pavilion System Semi-Perm Peaking  
11 Tap project, referred to as the Pavilion  
12 Project.

13 A. This project, as described beginning on page 600  
14 of Exhibit\_\_ (GCE-07), is located in RG&E's  
15 service territory and includes the construction  
16 of a semi-permanent LNG injection tap. The  
17 injection site will include a meter and  
18 regulator located inside a building, gas  
19 odorization equipment, overpressure protection,  
20 a connection point to an LNG vaporizer outlet,  
21 an area for two to three tractor trailers  
22 carrying LNG to park and inject, physical  
23 security measures such as SCADA, lighting and  
24 fencing, and a generator.

1 Q. Why is the project needed?

2 A. The Company states that all six points of  
3 delivery for its Pavilion division are located  
4 on the BH Eastern Gas Transmission and Storage  
5 pipeline, or BHEGTS, which does not have  
6 additional peak day capacity available. The  
7 Company points out that its contractual maximum  
8 daily demand obligation, or MDDO, at its East  
9 Avon point of delivery is 243 MCFH. However,  
10 since 2019 the Company has exceeded that MDDO at  
11 East Avon 14 times. The Company models a design  
12 day flow rate at East Avon to be 329 MCFH and  
13 estimates that the MDDO of 243 MCFH will be  
14 surpassed when the average daily temperature is  
15 below 10 degrees Fahrenheit. Therefore, the  
16 Company claims it needs to procure additional  
17 capacity on a design day to avoid exceeding its  
18 MDDO at East Avon and incur potential financial  
19 penalties or be unable to serve firm customers  
20 on a peak day.

21 Q. Has the Company attempted to increase its MDDO  
22 with BHEGTS at its East Avon point of delivery?

23 A. Yes. The response to DPS-903 shows  
24 communications between the Company and BHEGTS

1           about the possibility of increasing its MDDO at  
2           East Avon, and the response from BHEGTS showing  
3           an increase is not possible.

4   Q.    What factors have caused the increase in design  
5           day flow rate at East Avon?

6   A.    The Company states in the response to DPS-903  
7           that the addition of new customer load and  
8           resulting higher consumption during peak cold  
9           weather conditions has led to the increased  
10          design date flow rate at East Avon.

11   Q.    What financial penalties has the Company  
12          incurred since 2019 for the 14 times it exceeded  
13          its MDDO?

14   A.    None, although the Companies' response to DPS-  
15          903 notes that the decision to assess penalties  
16          lies solely with BHEGTS.

17   Q.    Has the Company been unable to provide service  
18          to any firm customers as a result of exceeding  
19          its MDDO in the past?

20   A.    No. The Companies indicate in the response to  
21          DPS-903 that NYSEG has been able to serve all  
22          firm customers without outages, even during  
23          periods when MDDOs were exceeded at East Avon.

1 Q. What potential operational or financial risks  
2 would result from continuing to exceed the MDDO  
3 at East Avon?

4 A. The Companies state in the response to DPS-903  
5 that NYSEG would be operationally able to  
6 maintain service to all customers by exceeding  
7 its MDDO. However, the financial penalty for  
8 that could result in a minimum fine of \$50,000  
9 for that day. The penalties are defined as the  
10 greater of \$25 per Dth or three times the  
11 penalty index price.

12 Q. What is the project in-service date?

13 A. The Company anticipates construction of the LNG  
14 peaking facility in the first half of 2026, to  
15 be completed in the second half of 2026.

16 Q. What is the status of internal approvals for the  
17 project?

18 A. The internal approval status is IP3 Partial  
19 Approval.

20 Q. How was the project cost developed?

21 A. In Exhibit\_\_ (GCE-07) on page 601, the Companies  
22 state they developed the cost based on  
23 conversations with internal personnel that  
24 operate NYSEG-owned LNG peaking facilities and

1 contractors that did a similar installation in  
2 Walton, New York.

3 Q. Was there a competitive bidding process for the  
4 project?

5 A. Yes.

6 Q. What is the status of that bidding process?

7 A. The site evaluation has been bid, for which the  
8 Company selected the lowest bid. The Company  
9 anticipates the project will be bid as well.

10 Q. Do you have any concerns with the cost estimate?

11 A. Yes. For the same reasons stated for the Goshen  
12 Peaking-Tap Project, we recommend the Commission  
13 find that the contingency of 40 percent is too  
14 high. We recommend a more reasonable 20 percent  
15 contingency, reducing the cost from \$3,258,316  
16 to \$2,801,008.

17 Q. Was this project included in a previous rate  
18 filing?

19 A. No.

20 Q. Are there any FTEs associated with this project?

21 A. No.

22 Q. What alternatives were considered for this  
23 project?

24 A. In Exhibit\_\_ (GCE-07) page 601, the Companies

1 state that they considered a CNG alternative to  
2 LNG. However, the Companies claim the CNG  
3 injection site would be much costlier than an  
4 LNG site, and an LNG site would leave fewer  
5 stranded costs in the event the demand decreases  
6 and the injection site was no longer needed.  
7 The Companies also considered constructing a  
8 pipeline to obtain a new point of delivery on a  
9 pipeline with available capacity. However, the  
10 East Avon point of delivery is more than 10  
11 miles from the nearest pipeline with additional  
12 capacity and the Company estimates the cost to  
13 install that length of main would be tens of  
14 millions of dollars, and therefore did not  
15 pursue the alternative.

16 Q. Did the Company consider any NPAs?

17 A. The Companies state NYSEG will solicit the  
18 market for NPA solutions.

19 Q. Will the Company engage local stakeholders  
20 directly about the nature of the traditional  
21 solution and the amount of demand reduction  
22 needed for a potential NPA?

23 A. The response to DPS-903 states that the  
24 Companies state NYSEG intends to issue the RFP

1 in 2025 and will engage stakeholders after the  
2 RFP is issued.

3 Q. Do you recommend adjusting the project schedule  
4 to accommodate a potential NPA solution?

5 A. Yes. We recommend delaying the project one  
6 year, until 2027, to allow more time for the  
7 Company, stakeholders and the local  
8 municipalities to assess the viability of an NPA  
9 solution.

10 Q. Is this project located within a disadvantaged  
11 community?

12 A. No.

13 Portable CNG/LNG Emergency Skid

14 Q. Describe the projects for a Portable LNG and CNG  
15 Emergency Skid.

16 A. As described beginning on page 427 of  
17 Exhibit\_\_ (GCE-07), these projects consist of two  
18 separate portable skids capable of injecting  
19 either LNG or CNG anywhere on either Companies'  
20 gas distribution systems. The skids are mobile  
21 units and contain the equipment necessary to  
22 inject either CNG or LNG at various pressures  
23 into the Companies' distribution systems to  
24 maintain system pressures in case of any

1 emergency situation. There would be one skid  
2 for LNG and one skid for CNG. The Companies  
3 propose sharing the skids between NYSEG and RG&E  
4 and allocating the costs between both companies.

5 Q. Why is the project needed?

6 A. In Exhibit\_\_ (GCE-07), the Companies state that  
7 the skids would provide increased reliability in  
8 the event of an emergency, allowing the  
9 Companies to inject either CNG or LNG as needed  
10 and not rely on a third-party vendor to have the  
11 equipment necessary for injection.

12 Q. Have there been emergency situations in the past  
13 that the Companies would have used the skids to  
14 address?

15 A. Yes. The response to DPS-344 describes two  
16 instances that the Company would have used the  
17 skids to address an emergency situation. The  
18 first was in December of 2020 in NYSEG's Elmira  
19 division and the second was in the fall of 2023  
20 on the Company's Walton-Deposit lateral. The  
21 first event put service at risk for 17,000  
22 customers, though none were ultimately  
23 interrupted, and the second event would have  
24 impacted 587 customers.

1 Q. How did the Companies address these situations  
2 without the proposed LNG and CNG skids?

3 A. For the first instance in Elmira, the Company  
4 was able to augment flow into its distribution  
5 system to alleviate the issue. For the second  
6 instance in 2023, NYSEG installed an emergency  
7 LNG tap and temporary reinforcement loop.

8 Q. Do the Companies expect an increased risk of  
9 emergency events in the future?

10 A. Not specifically, though emergency events are  
11 not generally able to be forecast. The  
12 Companies, in Exhibit\_\_ (GCE-07), stress the  
13 importance of emergency preparedness and the  
14 risk related to customer outages during the  
15 heating season.

16 Q. How do the Companies allocate the cost of the  
17 skids between NYSEG and RG&E?

18 A. Since the skids will be available for use by  
19 both Companies, the capital costs are allocated  
20 between the two Companies. As shown in  
21 Exhibit\_\_ (GCE-05), \$530,000 is shown in NYSEG's  
22 capital budget in 2026 and \$492,000 is shown in  
23 RG&E's capital budget in 2026 for the LNG skid.  
24 For the CNG skid, \$1.6 million is shown in

1 NYSEG's capital budget in 2029 and \$1.5 million  
2 is shown in RG&E's capital budget in 2029.  
3 However, according to the response to DPS-789,  
4 the Companies state the cost of the skids is  
5 allocated 50/50 between the two Companies.

6 Q. Do you agree with this allocation?

7 A. No. We recommend allocating the costs by  
8 customer counts from the historic test year.  
9 This would allocate 54 percent of costs to RG&E  
10 and 46 percent of costs to NYSEG. We also note  
11 that the Companies did not allocate costs evenly  
12 between NYSEG and RG&E as stated in their  
13 response to DPS-789.

14 Q. What is the project in-service date?

15 A. The skids are scheduled to be acquired and  
16 operational by the third quarter of 2029.

17 Q. What is the status of internal approvals for the  
18 project?

19 A. The internal approval stage is IP1 Originate.

20 Q. How was the project cost developed?

21 A. The Companies state that the cost of the skids  
22 was developed with regulatory safety code  
23 requirements in mind and through consultation  
24 and conceptual planning with vendors. The

1           Companies provide an itemized cost estimate for  
2           the CNG skid in Exhibit\_\_ (GCE-07) on page 429.

3   Q.   Was there a competitive bidding process for the  
4           project?

5   A.   Yes, according to the Companies' response to  
6           DPS-789.

7   Q.   Was this project included in a previous rate  
8           filing?

9   A.   No.

10  Q.   Are there any FTEs associated with this project?

11  A.   No.

12  Q.   What alternatives were considered for this  
13           project, including NPAs?

14  A.   The Companies did not list any alternatives for  
15           the skids.

16  Q.   Where would the skids be stored when not in use?

17  A.   As stated in the response to DPS-789, the  
18           Companies have not determined a location at this  
19           time.

20  Q.   How can the Companies ensure they can transport  
21           the skids to an affected area in an emergency  
22           quickly enough to be effective?

23  A.   The response to DPS-789 states that the skids  
24           can be mounted on a trailer and towed.

1 Q. Is this project located within a disadvantaged  
2 community?

3 A. That cannot be determined without a storage  
4 location. However, it is unlikely that the  
5 storage of the skids would pose any impact to  
6 the local community, as they will not be  
7 operated at the storage location. The skids  
8 would be operated in all communities in the  
9 Companies' service territory as needed and  
10 provide a benefit throughout all distribution  
11 systems and communities.

12 Q. Do you agree that the LNG and CNG skids are  
13 necessary?

14 A. We agree with the Companies that having a way to  
15 inject additional non-pipeline gas supply into  
16 its distribution system in the event of an  
17 emergency is beneficial to customers by  
18 improving reliability. However, we also note  
19 that the Companies have not had to interrupt  
20 service in the past due to emergency events and  
21 were able to find other solutions. Therefore,  
22 to balance affordability and improvements to  
23 reliability, we recommend that the Companies  
24 pursue the LNG skid only, as it is less costly

1 than the CNG skid. We also recommend that the  
2 Companies develop a detailed plan that includes  
3 a storage location for the LNG skid, contracts  
4 with suppliers to ensure gas supply is necessary  
5 when needed, and a plan to transport the skid to  
6 various injection points. Finally, we note the  
7 result of our reallocation of LNG skid costs  
8 between NYSEG and RG&E based on customer counts  
9 is shown in Exhibit\_\_ (SGIOP-2).

10 MF60 Phase I, III, IV

11 Q. Describe the proposed MF60 SE Phase I, III and  
12 IV projects, as well as the completed MF60 SE  
13 Phase II project, collectively referred to as  
14 the MF60 Southeast Projects.

15 A. As described beginning on page 579 of  
16 Exhibit\_\_ (GCE-07), the MF60 Southeast Projects  
17 involve the installation of additional gas main  
18 to connect and reinforce RG&E's gas distribution  
19 system to increase system pressures in the Town  
20 of Farmington. MF60 SE Phase II was completed  
21 in 2020 and was scheduled with a municipal  
22 project to increase efficiency. The Companies  
23 state that RG&E will complete Phase III by the

1 end of 2026, Phase I by the end of 2027, and  
2 Phase IV by the end of 2028.

3 Q. What is the scope of MF60 SE Phase I?

4 A. As described beginning on page 579 of  
5 Exhibit\_\_(GCE-07), this project will install  
6 13,100 feet of 12-inch wrapped steel main from  
7 regulator station 428 to the intersection of  
8 State Route 251. It also includes the rebuild  
9 of regulator station 428 to accommodate the  
10 additional capacity.

11 Q. What specific upgrades will be required at  
12 regulator station 428?

13 A. The list of specific upgrades is shown in the  
14 response to DPS-971.

15 Q. What is the scope of MF60 SE Phase III?

16 A. As described beginning on page 587 of  
17 Exhibit\_\_(GCE-07), this project will install  
18 19,000 feet of 6-inch medium density  
19 polyethylene pipe, or MDPE, along Dryer Road,  
20 Malone Road, Boughton Hill Road, from Willis  
21 Hill Road to State Route 441.

22 Q. What is the scope of MF60 SE Phase IV?

23 A. As described beginning on page 577 of  
24 Exhibit\_\_(GCE-07), this project will include the

1 installation of 14,600 feet of eight-inch  
2 polyethylene pipe, referred to as PE, connecting  
3 the existing six-inch steel main on Hook Road to  
4 the existing four-inch main south of the  
5 railroad tracks, crossing the New York State  
6 Thruway and the Ontario County IDA railroad.

7 Q. Why is the project needed?

8 A. The Companies state the MF60 SE Projects are  
9 needed for reliability purposes, as described  
10 beginning on page 578 of Exhibit\_\_ (GCE-07).  
11 System pressures on a design day in Farmington,  
12 the endpoint of RG&E's gas distribution system  
13 south of the City of Rochester, without the MF60  
14 SE projects are modeled to be as low as 18-psig,  
15 which is 30 percent of MAOP. With the MF60 SE  
16 Phase I through III projects completed, that  
17 increases to 30-psig, or 50 percent of MAOP.  
18 With MF60 SE Phase IV completed, the endpoint  
19 pressure will be 46-psig, or 76 percent MAOP.

20 Q. What is causing the low pressures in Farmington?

21 A. The Companies explain that the Town of  
22 Farmington, and the nearby Town of Victor to the  
23 west of Farmington, have seen significant  
24 population growth. The Company cites the US

1 Census Bureau from 1990 to 2010 showing  
2 population growth of 98.5 percent in Victor and  
3 13.9 percent in Farmington. The Companies also  
4 specify several residential housing developments  
5 that have been constructed or will be  
6 constructed.

7 Q. What is the status of internal approvals for the  
8 project?

9 A. MF60 SE Phase I is in the IP3 Partial Approval  
10 stage. MF60 SE Phase III is in the IP3  
11 Financial Execute stage. MF60 SE Phase IV is in  
12 the IP1 Originate stage.

13 Q. Was this project included in a previous rate  
14 filing?

15 A. No. However, MF60 SE Phase II was authorized by  
16 the Commission in its Order Approving Electric  
17 and Gas Rate Plans in Accord with Joint  
18 Proposal, with Modifications, issued November  
19 19, 2020, or the 2020 Rate Order.

20 Q. Are there any FTEs associated with this project?

21 A. No.

22 Q. What alternatives were considered for the MF60  
23 SE Phase IV project?

24 A. The Company considered one alternative for the

1 MF60 SE phase IV project, replacing existing 6-  
2 inch steel pipe with 8-inch HDPE from district  
3 regulator station 415 to just north of the  
4 intersection of High Street and Aldridge Road.

5 Q. How much would this alternative have cost?

6 A. As shown in the response to DPS-628, the  
7 Companies state the cost would have been \$2.3  
8 million.

9 Q. Why did the Company not select this alternative?

10 A. The Companies state that it would not have as  
11 much benefit to RG&E's system pressures as the  
12 selected project.

13 Q. What alternatives were considered for the MF60  
14 SE Phase I and III projects?

15 A. The Companies state the construction of an  
16 additional point of delivery station in the area  
17 could be an alternative. However, the Companies  
18 state this alternative was cost prohibitive and  
19 thus RG&E did not consider it.

20 Q. Were NPAs solutions considered for any of the  
21 MF60 SE Projects?

22 A. Yes. The Company states an NPA solution was  
23 solicited for the phase I and III projects but  
24 did not result in a financially or technically

1           viable alternative.

2   Q.   How much design day demand reduction was  
3       solicited in those NPAs?

4   A.   As stated in the response to DPS-971, the  
5       Company sought design day reduction of 120 to  
6       140 MCFH.

7   Q.   Are there any other capital projects that would  
8       address the design day endpoint pressure on the  
9       MF60 SE system?

10  A.   Yes.  The response to DPS-1111 states that the  
11       asset condition project Rebuild Station 449 -  
12       Valentown Rd & CR9 would impact the design day  
13       endpoint pressure on the MF60 SE system.  
14       Specifically, the response states that if the  
15       Station 449 rebuild and the County Road 9 work  
16       was completed, the design day endpoint pressure  
17       on the MF60 SE system would be 38.1 psig, or 64  
18       percent of MAOP, without completing the MF60 SE  
19       projects.

20  Q.   As a result, what is your recommendation  
21       concerning these projects?

22  A.   The Rebuild Station 449 - Valentown Rd & CR9 is  
23       scheduled to be completed for \$1.294 million in  
24       2028.  The MF60 SE projects total combined cost

1 is approximately \$21 million and will be  
2 completed between 2026 and 2028. If the Rebuild  
3 Station 449 - Valentown Rd & CR9 project  
4 increases the design day system endpoint  
5 pressure to 38.1 psig, or 64 percent of MAOP, we  
6 recommend that the completion of this project  
7 would solve the MF60 SE system reliability issue  
8 and make the MF60 SE Projects unnecessary.

9 Therefore, we have removed the MF60 SE Projects  
10 from our recommended capital budget shown in  
11 Exhibit\_\_ (SGIOP-2). Further, we recommend that  
12 the Rebuild Station 449 - Valentown Rd & CR9 be  
13 completed in 2027 so that the MF60 SE system low  
14 pressure issues are resolved more quickly.

15 Q. Are any of the MF60 SE Projects located within a  
16 disadvantaged community?

17 A. No.

18 Low Pressure Relief Valve Program

19 Q. What is the Low Pressure Relief Valve Program?

20 A. This program is described in the response to  
21 DPS-541. The intent of the program is to  
22 improve safety by enhancing over pressure  
23 protection at low pressure regulator stations.

24 Q. Does this program only exist at NYSEG?

1 A. Yes. As stated in the response to DPS-541, RG&E  
2 does not have any low-pressure regulator  
3 stations that meet the requirements of this  
4 program.

5 Q. Have the actual expenditures in this program  
6 been variable over the most recent five years?

7 A. Yes. The response to DPS-541 shows the actual  
8 expenditures, by year, from 2020 through 2024.  
9 Over that time, the annual expenditures have  
10 ranged between \$5,551 in 2023 and \$285,173 in  
11 2020.

12 Q. How does NYSEG forecast the cost of this  
13 program?

14 A. NYSEG is forecasting \$548,000 in 2026 and  
15 \$549,000 in 2027. According to the Companies'  
16 response to DPS-541, the Company used 2022 work  
17 orders and adjusted for increases in material  
18 costs and inflation, which the Companies  
19 provided in their responses to DPS-265 and DPS-  
20 337.

21 Q. Do you agree with those forecast costs?

22 A. No. NYSEG forecasts very high expenditures for  
23 this program in 2026 and 2027 that are nearly  
24 doubled the most they have spent on this program

1 in a single year since 2020, with that  
2 expenditure occurring five years ago in 2020.  
3 Since 2020, NYSEG has not spent more than  
4 \$170,484 in a single year on this program. The  
5 other three years in that time period include  
6 \$28,123 in 2021, \$5,551 in 2023 and \$15,290 in  
7 2024.

8 Q. How do you recommend forecasting costs for this  
9 program?

10 A. This program is important for improving the  
11 safety of the NYSEG's low pressure regulator  
12 stations. However, the forecast needs to  
13 reasonably align with a level of spending that  
14 NYSEG has demonstrated can be achieved.  
15 Therefore, we recommend using a five-year  
16 average of the most recent historical actual  
17 expenditures, adjusted for inflation, to  
18 forecast the budget for this program. Our  
19 recommended forecast is included in  
20 Exhibit\_\_ (SGIOP-2).

21 Critical Valve Installations, Binghamton

22 Q. What is the Critical Valve Installations,  
23 Binghamton program?

24 A. Per the Companies' response to DPS-540, this

1 program is specific to bringing the Binghamton  
2 medium pressure system into compliance with  
3 current code standards by installing valves  
4 throughout the system to allow the Company to  
5 adequately be able to isolate certain sections.

6 Q. Does this program only exist at NYSEG?

7 A. Yes, this program is specific to the Binghamton  
8 medium pressure system at NYSEG.

9 Q. Have the actual expenditures in this program  
10 been variable over the most recent five years?

11 A. Yes. Those expenditures are shown in the  
12 response to DPS-540. The Company has spent  
13 \$128,178 in 2020, \$13,476 in 2021, \$0 in 2022,  
14 \$172,710 in 2023 and \$77,532 in 2024.

15 Q. How does NYSEG forecast the cost of this  
16 program?

17 A. The Company used its 2024 MSA, adjusted for  
18 inflation, to forecast these costs. The Company  
19 forecasts expenditures of \$190,000 in each year  
20 for 2026 and 2027.

21 Q. Do you agree with those forecast costs?

22 A. No. The Company has not spent \$190,000 in a  
23 single year in any of the most recent five years  
24 on this program.

1 Q. How do you recommend forecasting costs for this  
2 program?

3 A. We used a five-year average expenditure of  
4 \$78,379, adjusted for inflation, resulting in  
5 \$92,000 in 2026 and \$104,000 in 2027. We argue  
6 that this forecast is more accurate since it  
7 aligns more closely with the Company's actual  
8 spending on critical valve installations since  
9 2020.

10 Lansing Low Pressure Contingency Plan

11 Q. What is the scope of the Lansing Low Pressure  
12 Contingency Plan?

13 A. The scope of the project, as described in the  
14 Companies' response to DPS-609, is solely for  
15 site evaluation and obtaining a Department of  
16 Environmental Conservation, or DEC, permit for a  
17 semi-permanent LNG injection tap into the  
18 Lansing gas distribution system, in NYSEG's  
19 service territory. The scope does not include  
20 the construction of the injection tap.

21 Q. Why is NYSEG proposing this project?

22 A. On June 21, 2021, in Case 17-G-0432, the  
23 Commission issued an Order Approving Petition  
24 for Non-Pipe Alternative Projects, with

1 Modifications, referred to as the 2021 NPA  
2 Order. The 2021 NPA Order requires NYSEG to  
3 monitor and report the pressure at the Lansing  
4 School. Additionally, the 2021 NPA Order  
5 requires that NYSEG file an implementation plan  
6 within 30 days following a measurement of  
7 pressure of 31 psig or lower. The 2021 NPA  
8 Order specifies that the contingency plan must  
9 include an emergency source of supply to  
10 maintain system pressures. Finally, on page 21,  
11 the 2021 NPA Order states that "NYSEG will not  
12 be required to implement its contingency plan  
13 and associated alternate supply source if it is  
14 able to reduce peak day demand and maintain the  
15 system pressure at the Lansing School above the  
16 31 psig threshold." The semi-permanent LNG  
17 injection tap could provide the alternate supply  
18 source required for the contingency plan.

19 Q. Has NYSEG filed the contingency plan?

20 A. No. The pressure at the Lansing School, as  
21 shown in Attachment 1 to the response to DPS-  
22 609, has not fallen below 33.57 psig.

23 Q. Does the 2021 NPA Order require the contingency  
24 plan to be filed within 30 days, or enacted

1           within 30 days?

2    A.    While the 2021 NPA Order requires that NYSEG  
3           file the contingency plan within 30 days, it  
4           also states that the plan will detail actions  
5           required to maintain system reliability if the  
6           pressure at the Lansing School drop below 31  
7           psig.  Therefore, if the pressure at the Lansing  
8           School drops to or below 31 psig, it is  
9           important that NYSEG be able to implement the  
10          contingency plan expeditiously.

11   Q.    Does the 2021 NPA Order require anything else?

12   A.    Yes, the 2021 NPA Order requires NYSEG to engage  
13          stakeholders and seek feedback before finalizing  
14          the contingency plan.

15   Q.    Has the Company done so?

16   A.    No, it has not.  However, the contingency plan  
17          has not yet been filed publicly in Case 17-G-  
18          0432.  The Companies provided the draft  
19          contingency plan in their response to DPS-609.

20   Q.    What are your recommendations concerning this  
21          project?

22   A.    First, we recommend that the Commission require  
23          the Company to continue its NPA efforts in  
24          Lansing that the Commission approved in the 2021

1 NPA Order and continue to assess possible  
2 further demand reduction to avoid the need for  
3 additional supply. Recognizing that NYSEG must  
4 be able to act quickly to implement a  
5 contingency plan if the pressure at the Lansing  
6 School does drop to or below 31 psig, we further  
7 recommend that NYSEG continue to develop its  
8 draft contingency plan. In line with this  
9 recommendation, we agree that NYSEG's proposal  
10 to seek a permit for the alternate supply is  
11 reasonable at this time. This will help ensure  
12 that the NYSEG is prepared to finalize and  
13 implement a contingency plan if it becomes  
14 necessary, as required by the 2021 NPA Order.  
15 Further, we recommend that NYSEG inform and  
16 request feedback from stakeholders prior to  
17 finalizing its contingency plan. NYSEG could  
18 seek stakeholder feedback on its draft  
19 contingency plan while these rate proceedings  
20 are still in progress. In the event that it has  
21 not done so by the time of a rate order,  
22 however, we recommend that the Commission  
23 require NYSEG to solicit stakeholder feedback  
24 before November 1, 2026. This will ensure that

1 NYSEG can be able to file and enact a final  
2 contingency plan in the event the pressure at  
3 the Lansing school reaches 31 psig or below  
4 during the winter of 2026-27.

5 NPAs

6 Q. What is the Companies' NPA screening process?

7 A. The Companies consider all gas capital projects  
8 for NPA solutions. If is the Companies  
9 determine that an NPA solution is possible, an  
10 RFP is developed, submitted, and then if viable  
11 solutions are included in response, an NPA is  
12 pursued.

13 Q. Do you have any recommendations concerning the  
14 Companies' NPA process?

15 A. Yes. For several capital projects, we noted  
16 that the Companies do not engage with local  
17 stakeholders and municipalities until an RFP is  
18 completed for an NPA solution. Through the RFP  
19 process, a third party would assess and  
20 determine how much load reduction is possible  
21 and then submit a bid that includes plans to  
22 achieve that amount. However, by not engaging  
23 stakeholders publicly about the traditional  
24 pipeline solution and the amount of load

1 reduction necessary to avoid or delay the  
2 traditional solution, it is possible that the  
3 level of load reduction that a third party deems  
4 possible is understated. We recommend that the  
5 Companies engage local stakeholders and  
6 municipalities much earlier in the process to  
7 educate and inform about the traditional  
8 pipeline solution and the load reduction that  
9 would be necessary to avoid or delay that  
10 project. This could improve the potential bids  
11 received in the RFP process by allowing local  
12 stakeholders and municipalities the opportunity  
13 to perform community engagement and increase  
14 support for potential NPA solutions, maximizing  
15 their impact.

16 Q. What timeframe should the Companies be engaging  
17 local stakeholders and municipalities?

18 A. We recommend this occurs at least two years  
19 before a traditional project is scheduled to  
20 commence construction, and at least six months  
21 prior to completing an RFP. However, we stress  
22 that it should really be as early as possible,  
23 essentially as soon as the need is identified  
24 and a traditional pipeline solution is developed

1 with a known scope and cost, allowing for  
2 maximum community engagement.

3 Projects Amortized in CWIP

4 Q. Do the Companies propose to amortize any project  
5 costs?

6 A. Yes. The Companies propose to amortize capital  
7 costs for four projects. Specifically, the CM3D  
8 Transmission Pipeline and Caledonia Gate Station  
9 at RG&E and the DeRuyter Pipeline Replacement  
10 and NPA costs at NYSEG.

11 Q. Describe the CM3D Transmission Pipeline project.

12 A. This project was proposed by the Companies in  
13 Cases 19-E-0378, et al. and included in Appendix  
14 R of the Joint Proposal, the terms of which were  
15 adopted in the 2020 Rate Order. According to  
16 the Company's response to DPS-765, only  
17 preliminary engineering costs of \$1 million were  
18 approved by the 2020 Rate Order, with the  
19 Company actually incurring approximately \$0.9  
20 million in costs. The full project scope would  
21 have been the installation of 25,000 feet of 16-  
22 inch gas main with an MAOP of 250 psig, the  
23 construction of a new regulator station and an  
24 additional installation of 5,000 feet of 12-inch

1 gas main for a total project cost of \$20.2  
2 million. The need for the project was driven by  
3 customer growth and the need for an additional  
4 source of gas supply.

5 Q. Did the Companies request cost recovery of this  
6 project beyond the preliminary engineering costs  
7 approved by the 2020 Rate Order?

8 A. No. The response to DPS-765 states that the  
9 Company no longer has a need for the project for  
10 system reliability. Therefore, the full project  
11 has not been proposed in rate cases since the  
12 rate proceedings in Cases 19-E-0378, et al.

13 Q. Why does RG&E propose amortizing those project  
14 costs?

15 A. RG&E proposes to amortize the \$0.9 million over  
16 a 20-year period as the project will no longer  
17 be needed.

18 Q. Do you agree?

19 A. Yes. The project need was justified, and  
20 preliminary engineering costs were approved by  
21 the 2020 Rate Order. Therefore, these costs  
22 were prudently incurred and should be allowed to  
23 be recovered. We agree with the Companies'  
24 proposal to amortize the costs over a 20-year

1 period.

2 Q. Describe the Caledonia Gate Station project.

3 A. This project is a rebuild of the Caledonia Gate  
4 Station in RG&E service territory. Engineering  
5 and design costs of \$1.182 million were approved  
6 by the 2020 Rate Order. However, this project  
7 was ultimately excluded from the 2023 Rate Order  
8 over concerns raised by the Staff Gas  
9 Infrastructure and Operations Panel about the  
10 Companies' cost estimating process in those  
11 proceedings. The Companies maintain this  
12 project is needed as an asset condition concern  
13 and they propose to complete the rebuild in 2027  
14 for \$4.782 million. In the event the project is  
15 not included in the Commission-approved outcome  
16 in these proceedings, the Companies propose to  
17 amortize the \$0.3 million in actual engineering  
18 and design costs spent on this project over a  
19 20-year period.

20 Q. Do you agree?

21 A. Yes. However, we note that we recommend that  
22 the project is necessary in these proceedings  
23 and therefore an amortization of the \$0.3  
24 million in actual engineering and design costs

1 is not necessary, given that once the project is  
2 placed in service in 2027, these costs will be  
3 added to the Companies' plant in service  
4 balance. Alternatively, if the project is  
5 ultimately not included in the Commission  
6 approved outcome in these proceedings, we agree  
7 that the Companies' amortization proposal is  
8 reasonable.

9 Q. Describe the DeRuyter Pipeline Replacement  
10 project.

11 A. This project was originally proposed by the  
12 Companies in Cases 15-E-0283, et al., referred  
13 to as the 2015 Rate Filing, in which the  
14 Companies stated the need for the project as a  
15 capacity improvement to reduce reliance on the  
16 compressor in the Town of Norwich. In those  
17 proceedings, the Commission authorized the  
18 project and its costs of \$32.5 million in the  
19 Order Approving Electric and Gas Rate Plans in  
20 Accord with Joint Proposal, issued June 15,  
21 2016, or the 2016 Rate Order. The project would  
22 have resulted in replacement of 25 miles of  
23 eight-inch gas main with 10-inch gas main.

24 Q. Did the Company complete the project?

1 A. No. According to the Companies' corrections and  
2 update testimony of the Gas Capital Expenditures  
3 Panel, \$4.3 million in costs have been incurred.  
4 The 2020 Rate Order and 2023 Rate Order both did  
5 not approve costs for the project. Further, the  
6 2020 Rate Order adopted the terms of the 2020  
7 JP, in which Appendix M states that the Company  
8 may recover these costs along with any NPAs  
9 completed in the area.

10 Q. Has an NPA been completed?

11 A. No.

12 Q. Why does RG&E propose amortizing those project  
13 costs?

14 A. The Companies propose a new project in this case  
15 for the DeRuyter Pipeline, requesting recovery  
16 of the Article VII filing costs associated with  
17 permitting the replacement of the pipeline with  
18 the same size eight-inch and 10-inch main as the  
19 existing pipeline as an asset condition  
20 replacement rather than a replacement to  
21 increase capacity. The Companies plan to file  
22 that Article VII filing in 2029 and, if costs  
23 for the Article VII filing are included in the  
24 Commission approved outcome in this case,

1 include these costs in plant and service once  
2 the replacement is in service. Otherwise, the  
3 Company proposes to amortize the \$4.3 million in  
4 previously incurred costs over 20 years.

5 Q. Do you agree?

6 A. Yes. Further, we note that we recommend  
7 including the costs of the DeRuyter Pipeline  
8 Article VII filing in 2029, and therefore no  
9 amortization is needed.

10 Q. Describe the NPA costs that NYSEG proposes to  
11 amortize.

12 A. The Company is proposing to discontinue the  
13 Lansing Pipeline project and Lansing Compressor  
14 project and amortize the incurred costs of \$1.7  
15 million and \$0.1 million, respectively, for the  
16 two projects.

17 Q. What are the Lansing Pipeline project and  
18 Lansing Compressor project?

19 A. In its 2015 Rate Filing, NYSEG proposed the  
20 Lansing Pipeline project to address low  
21 pressures in the Town of Lansing, where a  
22 moratorium on gas service was issued in February  
23 2015. The 2016 Rate Order approved the Lansing  
24 Pipeline project. However, after discussions

1 with stakeholders, in July 2017, NYSEG filed a  
2 petition with the Commission for a compressor  
3 pilot project in Case 17-G-0432, or the Lansing  
4 Compressor project, an alternative solution to  
5 the Lansing Pipeline project. On November 16,  
6 2017, the Order Authorizing Natural Gas  
7 Compressor Pilot Project, referred to as the  
8 2017 Compressor Order, approved the Company's  
9 proposed Lansing Compressor project and further  
10 directed the Company to issue an RFP for an NPA  
11 solution to the moratorium. The 2021 NPA Order  
12 directed the Company to pursue a series of NPA  
13 solutions to address the Lansing reliability  
14 issues and moratorium instead of the Lansing  
15 Compressor project, assuming the NPA solutions  
16 were more cost effective. The 2021 NPA Order  
17 referenced Appendix M of the 2020 JP adopted in  
18 the 2020 Rate Order, which states that NPA  
19 projects without a clear measurable amortization  
20 period should be amortized over a 20-year  
21 period.

22 Q. Do you agree with the Company's proposed  
23 amortization of the Lansing Pipeline project  
24 costs and Lansing Compressor project costs?

1 A. Yes. These projects were directed by the  
2 Commission in various orders and ultimately  
3 abandoned for different solutions. Therefore,  
4 the costs were incurred prudently. Further, the  
5 NPA solutions approved by the 2021 NPA Order are  
6 currently being undertaken and the Company plans  
7 to abandon both projects. Therefore, the  
8 proposal is reasonable.

9 Operating Expenses

10 Communications - Reporting Gas Odors

11 Q. Provide a description of the work performed  
12 under this program.

13 A. This program includes various customer  
14 communication items including brochures on  
15 natural gas and odorant smells, first responder  
16 letters and gas safety informational materials  
17 with postage, radio and printed ad campaigns for  
18 Dig Safe and CO Safety, and educational services  
19 for gas safety.

20 Q. Why is this program needed, and what are the  
21 benefits to ratepayers?

22 A. This program educates the Companies' customers,  
23 contractors, first responders, educators,  
24 schools, and the general public of various gas

1 safety topics. Safety education reduces the  
2 chance of pipeline emergencies and occurs  
3 throughout the year.

4 Q. Is this a new program, or existing program?

5 A. This is an existing program.

6 Q. Do the Companies hire an outside contractor to  
7 perform this work, or is the work performed with  
8 its internal workforce?

9 A. The work is performed with internal workforce.

10 Q. How do the Companies develop the Rate Year  
11 operating expenses for this program?

12 A. The Rate Year values are forecast by adding  
13 inflation to the normalized historic test year.

14 Q. What does the Companies' CO Safety work include?

15 A. As stated in the Companies' response to DPS-  
16 1082, customers delayed the start of home  
17 heating as a result of an unusually warm October  
18 2024. The Companies ran the CO Safety Ad  
19 Campaign a second time in December 2024 to align  
20 with colder temperatures and increased heating  
21 use to ensure all customers received the safety  
22 information.

23 Q. Does the Company plan to run two CO Safety Ad  
24 Campaigns in the Rate Year?

1 A. No. Typically this ad campaign runs once per  
2 year.

3 Q. Did the Company normalize the costs of the CO  
4 Safety Ad Campaigns to reflect running the ad  
5 campaign only once in the Rate Year?

6 A. No, according to the Companies' response to DPS-  
7 1082, it did not.

8 Q. What is your recommended adjustment?

9 A. We recommend removing \$121,000 associated with a  
10 second CO Safety Ad Campaign in the Rate Year,  
11 and adjusting the budgets to reflect the Staff  
12 inflation rate where applicable, bringing the  
13 total budget to \$543,000 for NYSEG and \$217,000  
14 for RG&E.

15 Gas Tapping Tees

16 Q. Provide a description of the work performed  
17 under this program.

18 A. As stated, beginning on page 38 of the Gas  
19 Operations Panel Testimony, the Commission  
20 directed the Companies to conduct random  
21 sampling of approximately 450 sites with known  
22 PermaLock Mechanical Tapping Tee, or PMTT  
23 installations in the Companies' service areas.  
24 The sampling included the inspection of over

1           3,700 PMTT installations. On December 20, 2024,  
2           the Commission issued Order Regarding Integrity  
3           Management Plans in Case 23-G-0083, which  
4           directed the Companies to include the fees as a  
5           factor in the Companies' integrity management  
6           plans, and the expectation that the Companies  
7           will take proactive measures to replace or  
8           repair components when public harm is at risk.  
9           The Companies contracted with Gas Technology  
10          Institute's, or GTI, Operations Technology  
11          Development organization, or OTD, together  
12          referred to as GTI OTD, to conduct a Phase 2  
13          Study to evaluate PMTT life expectancy, risks,  
14          and actions recommended and issue a report.

15    Q.    Have the Companies received the final Phase 2  
16          Study Report from GTI OTD?

17    A.    Not yet. The Companies expect to receive  
18          conclusions by the end of 2025 or early 2026.

19    Q.    Is this a new program?

20    A.    Yes. The Companies propose operating expenses  
21          associated with potential remediation efforts  
22          associated with the results of the study filed  
23          in Case 22-G-0425. The Companies also propose  
24          recovery of deferred costs associated with the

1           sampling directed by the Commission.

2    Q.    Do the Companies have detailed plans for the  
3           remediation requirements?

4    A.    No.  As stated on page 42 of the Gas Operations  
5           Panel Testimony, the Companies are awaiting the  
6           final Phase 2 Study report from GTI OTD.

7    Q.    What are the costs previously incurred for the  
8           PMTT Sampling?

9    A.    As stated in the Companies' response to DPS-873,  
10           a total of \$3,522,909 has been spent on sampling  
11           for NYSEG between 2022 and 2024.  There was also  
12           \$471,441 spent on remediation for NYSEG in 2023.  
13           As stated in the Companies' response to DPS-876,  
14           \$1,761,756 was spent on sampling for RG&E in  
15           2023.  There was a total of \$49,620 spent on  
16           remediation for RG&E in 2023 and 2024.

17   Q.    How do the Companies propose to recover the  
18           deferred costs?

19   A.    As stated on page 42 of the Gas Operations Panel  
20           Testimony, the Companies propose to recover  
21           costs in base rates, amortized over a three-year  
22           period.

23   Q.    Do you agree with this proposal?

24   A.    Yes.  The Companies were directed by the

1 Commission to perform this work and should  
2 receive cost recovery.

3 Q. How do the Companies develop the Rate Year  
4 operating expenses for this program?

5 A. As stated on page 46 of the Gas Operations Panel  
6 Testimony, the Companies are proposing a  
7 baseline level of mitigation costs, considering  
8 the full inventory, potentially anomalous  
9 portion and the cost associated with anomalies  
10 that could require full replacement. The  
11 Companies propose a baseline cost of \$1,000,000  
12 for each Company in the Rate Year.

13 Q. What is the itemized breakdown of the baseline  
14 level of mitigation costs?

15 A. As stated in the Companies' responses to DPS-873  
16 and DPS-876, they have a range of potential  
17 requirements from PMTT Sampling and findings.  
18 The Companies state \$3,000 per replacement is a  
19 conservative estimate based on recent work.  
20 Calculating total project cost with confidential  
21 information, the proposed annual baseline of  
22 \$1,000,000 per Company is less than half of the  
23 total projected cost.

24 Q. How do the Companies propose reconciliation of

1 the Rate Year cost?

2 A. As stated on page 47 of the Gas Operations Panel  
3 testimony, the Companies are proposing a  
4 symmetrical cost reconciliation be applied to  
5 the amount included in base rates. In addition,  
6 the Companies propose to continue providing  
7 periodic filings on the updated cost estimates,  
8 work plans, and mitigation practices.

9 Q. How many PMTTs are installed on the Companies'  
10 gas mains?

11 A. As stated on page 43 of the Gas Operations Panel  
12 Testimony, there are 143,314 PMTTs within NYSEG  
13 and 156,749 within RG&E installed on gas mains  
14 sized four inches and under.

15 Q. What are the benefits to ratepayers from this  
16 program?

17 A. According to the Companies' responses to DPS-873  
18 and DPS-876, the program relates to the safety  
19 and integrity of the gas delivery system,  
20 providing a clear benefit to ratepayers.

21 Q. Do the Companies anticipate changes to its  
22 internal workforce to support the project?

23 A. As stated in the Companies' responses to DPS-873  
24 and DPS-876, there are no proposed workforce

1 changes related to PMTT.

2 Q. Do the Companies hire an outside contractor to  
3 perform this work, or is the work performed with  
4 its internal workforce?

5 A. As stated in the Companies' responses to DPS-873  
6 and DPS-876, they have not determined whether  
7 internal or external resources will be doing the  
8 work. The mitigation work would be managed like  
9 LPP replacements, and the resources will be  
10 addressed in the Companies' workplans.

11 Q. Without the final Phase 2 Study Report, do you  
12 think it is reasonable to include the Rate Year  
13 costs associated with Gas Tapping Tee  
14 remediation?

15 A. No, not at this time. Without the final Phase 2  
16 Study Report from GTI OTD, there are many  
17 unknowns including the scope of work, the  
18 resources needed to perform the work, all of  
19 which need to be known to develop an accurate  
20 project cost and the associated Rate Year cost.  
21 Therefore, our recommendation is to remove the  
22 proposed \$1 million Rate Year expense for each  
23 Company associated with this program.

24 Gas Meter Relocations

1 Q. Provide a description of the work performed  
2 under this program.

3 A. As described beginning on page 25 of the Gas  
4 Operations Panel testimony, the scope of work  
5 under this program includes relocating customer  
6 meters that are located inside a customer's  
7 premises to an outdoor location. The 2023 Rate  
8 Order approved a Meter Relocation Pilot program  
9 to perform this work.

10 Q. Has the description of work performed changed  
11 for the proposed program as compared to the  
12 Meter Relocation Pilot program?

13 A. No. Similar to the Meter Relocation Pilot  
14 program, the proposed program will continue to  
15 relocate customer meters to an outdoor location.

16 Q. Why is this program necessary?

17 A. As stated on page 27 of the Gas Operations Panel  
18 Testimony, relocating meters, regulators, or  
19 both to the outside of buildings make it easier  
20 for the Companies to perform mandated  
21 inspections, work, and meter readings without  
22 interruption to the customer. Meter relocations  
23 can also address safety concerns, giving  
24 emergency response personnel access in the event

1 of safety incidents, as well as eliminating  
2 medium-pressure service connections from inside  
3 buildings.

4 Q. What cost recovery are the Companies' proposing  
5 for meter relocations?

6 A. As stated on page 28 of the Gas Operations Panel  
7 Testimony, the 2023 Rate Order allows the  
8 Companies to defer Meter Relocation Pilot costs  
9 up to \$675,000 for NYSEG and \$825,000 for RG&E  
10 in each rate year subsequent to the third rate  
11 year of the Companies' current rate plan. The  
12 Companies are proposing to move these expenses  
13 to base rates and to increase the costs to  
14 \$1,500,000 for NYSEG and \$3,000,000 for RG&E for  
15 the Rate Year as set forth in Exhibit\_\_ (GOP-4).

16 Q. Do the Companies plan to continue to utilize  
17 deferred cost recovery for the Meter Relocation  
18 Programs?

19 A. No. The Companies propose to shift the costs of  
20 the program to base rates, subject to  
21 symmetrical reconciliation, which would have a  
22 deferral to reconcile to actual costs.

23 Q. What is the average cost to relocate each meter?

24 A. The Companies use a cost per relocation of

1           \$2,134 and \$2,436 for NYSEG and RG&E,  
2           respectively, to estimate the Rate Year budgets  
3           for this program. These costs are based on the  
4           relocation cost estimates from 2023. The  
5           Companies' response DPS-687, based on actual  
6           expenses from the pilot program, included  
7           average relocation costs of \$2,760 for NYSEG and  
8           \$3,039 for RG&E, per relocation.

9    Q.    What is included in the cost per relocation?

10   A.    The Companies' response to DPS-687 provided an  
11          itemized breakdown based on the 304 meters  
12          relocated by external contractors during the  
13          pilot program. The total cost per relocation  
14          includes an average material cost and average  
15          external labor cost.

16   Q.    How many meters did NYSEG relocate in the Pilot  
17          program, and what was the associated cost?

18   A.    According to the Companies' response to DPS-687,  
19          NYSEG completed 298 relocations, 119 with  
20          internal resources and 179 by external  
21          contractors. Utilizing the external  
22          contractors' costs, NYSEG had an average  
23          material cost of \$426 and an average external  
24          labor cost of \$2,334, resulting in a total cost

1 of \$2,760 per relocation. The average cost per  
2 relocation using internal resources was \$1,104.

3 Q. How many meters did RG&E relocate in the Pilot  
4 program, and what was the associated cost?

5 A. As stated in the Companies' response to DPS-687,  
6 RG&E completed 183 relocations, 58 with internal  
7 resources and 125 by external contractors.  
8 Utilizing the external contractors' costs, RG&E  
9 had an average material cost of \$1,018 and an  
10 average external labor cost of \$2,020, resulting  
11 in a total cost of \$3,039 per relocation. The  
12 average cost per relocation using internal  
13 resources was \$1,765.

14 Q. What is the cause of the significant variation  
15 between NYSEG's average material cost and RG&E's  
16 average material cost?

17 A. As stated in the response to DPS-687, NYSEG's  
18 average material cost was \$426 and RG&E's  
19 average material cost was \$1,018. As stated in  
20 the Companies' response to DPS-1110, the  
21 variation is due to the different types of meter  
22 relocation work performed. NYSEG focused on  
23 meters referred to as "up and ins," which  
24 require fewer materials and an easier

1 installation. RG&E relocations were mainly  
2 performed in single-family homes, which can  
3 require additional materials and installation to  
4 ensure the relocation meets safety and  
5 regulation requirements.

6 Q. How many indoor meters remain on the Companies'  
7 systems?

8 A. As stated on page 26 of the Gas Operations Panel  
9 Testimony, there are 64,000 indoor meters at  
10 NYSEG and 127,000 at RG&E. The Companies'  
11 response to DPS-687 reports 60,720 at NYSEG and  
12 122,842 at RG&E.

13 Q. How many meter relocations are planned for RY1?

14 A. As stated in workpaper NG-RRP-2-WP-11-MY,  
15 provided in response to DPS-263, NYSEG forecasts  
16 703 meter relocations in the Rate Year and in  
17 workpaper RG-RRP-2-WP-11-MY, also provided in  
18 response to DPS-263, RG&E forecasts 1,232 meter  
19 relocations in the Rate Year.

20 Q. How do the Companies plan to scale up the number  
21 of meter relocations from over 250 during the  
22 Pilot program to over 1,900 in the Rate Year?

23 A. As stated in the Companies' response to DPS-687,  
24 they plan to use external contractors dedicated

1 to relocations. The Companies also plan to  
2 continue relocating meters with their internal  
3 workforce when service line replacements,  
4 repairs and transfers are being performed. In  
5 addition, the Companies are pre-planning where  
6 work will occur as they have identified areas  
7 with large quantities of indoor meters.

8 Q. Do you agree that the Companies will be able to  
9 scale up the number of relocations in the Rate  
10 Year?

11 A. No. As stated in the Companies' response to  
12 DPS-687, there was a full ramp up of meter  
13 relocations with external contractors in late  
14 2024 and early 2025, with the total number of  
15 meter relocations by external contractors  
16 through April 2025 of 179 for NYSEG and 125 for  
17 RG&E. This is significantly below the proposed  
18 targets of 703 and 1,232 for the two Companies,  
19 respectively.

20 Q. How do the Companies develop the Rate Year  
21 operating expenses for this program?

22 A. The Companies used the RG&E \$2,436 per  
23 relocation and multiplied by 1,232 proposed  
24 meter relocations, resulting in \$3,001,152,

1           which RG&E approximated to \$3,000,000 for RG&E  
2           for Rate Year costs. NYSEG used \$2,134 per  
3           relocation multiplied by 703 meter locations,  
4           resulting in \$1,500,202, which NYSEG  
5           approximated to \$1,500,000 for Rate Year costs.

6   Q.   Do you recommend adjustments to the cost of the  
7        program in the Rate Year?

8   A.   Yes. We recommend adjusting the number of  
9        relocations in the Rate Year to a more realistic  
10       number that the Companies are likely to complete  
11       based on historical performance. For NYSEG, we  
12       recommend a total of 275 relocations, 60  
13       completed by internal workforce and 215  
14       completed by external contractors. Using  
15       historical costs per relocation for internal and  
16       external workforces results in a total budget of  
17       \$528,286 for the Rate Year. Applying this  
18       approach to RG&E results in 179 relocations, 29  
19       internal and 150 external, for a total Rate Year  
20       budget of \$419,876.

21   Q.   Do you agree with the proposed deferral  
22        treatment and symmetrical reconciliation of  
23        costs?

24   A.   Yes, but with modifications. We recommend that

1 the reconciliation is based on the forecasted  
2 cost per relocation. The Companies should  
3 report the number of relocations completed in  
4 the Rate Year and multiply that number by our  
5 forecast cost per relocation at each Company.  
6 If the resulting amount is higher or lower than  
7 the amount in base rates, each Company should  
8 then defer the difference. This provides cost  
9 certainty for ratepayers but allows the Company  
10 to recover higher costs if they achieve meter  
11 relocations above the levels forecast for the  
12 Rate Year.

13 Research and Development

14 Q. What types of Research and Development do the  
15 Companies participate in?

16 A. Research and Development includes Millenium,  
17 Internal Projects/Utilization Technology  
18 Development, or Internal/UTD, and New York State  
19 Energy Research and Development Authority, or  
20 NYSERDA.

21 Q. Is this a new program, or existing program?

22 A. Research and Development is an existing program.

23 Q. How do the Companies develop the Rate Year  
24 operating expenses for this program?

- 1 A. As stated on page 96 of the Gas Operations Panel  
2 Testimony, the Companies are proposing that the  
3 funding escalate at the general inflation rate  
4 instead of remaining constant, as has been done  
5 historically. RG&E also proposes adding funding  
6 to their Internal Projects/UTD budget to  
7 participate in GTI/UTD.
- 8 Q. What are the Companies' reasoning for the  
9 funding to increase with inflation?
- 10 A. As stated in the Companies' response to DPS-904,  
11 the Companies are adjusting the forecast funding  
12 to more accurately reflect rising costs.
- 13 Q. What is the cost of the Companies' participation  
14 in Internal Projects/UTD?
- 15 A. As stated in NYSEG's workpaper NG-RRP-2-WP-07-  
16 MY, provided in response to DPS-263, the Rate  
17 Year cost for NYSEG would be \$525,000. As  
18 stated in RG&E's workpaper RG-RRP-2-WP-07-MY,  
19 also provided in response to DPS-263, the Rate  
20 Year cost for RG&E would be \$497,000.
- 21 Q. Are there any subsections of Internal/UTD that  
22 RG&E does not participate in, but NYSEG does?
- 23 A. Yes. GTI/UTD, which the Companies propose RG&E  
24 begin to participate in.

1 Q. Why do the Companies propose to begin RG&E  
2 participation in GTI/UTD?

3 A. The Companies' response to DPS-904 claims that  
4 RG&E joining GTI/UTD would align with NYSEG's  
5 model and ensure customers benefit from the same  
6 innovation and technological advancement level.

7 Q. What are the risks associated with RG&E not  
8 participating in GTI/UTD?

9 A. As stated in the Companies' response to DPS-904,  
10 there is a risk of falling behind and missing  
11 opportunities to improve safety, efficiency and  
12 environmental performance.

13 Q. What projects have resulted from NYSEG's  
14 participation in GTI/UTD?

15 A. The Companies state in response to DPS-904 that  
16 several programs have benefitted indirectly from  
17 UTD, including NYSEG's Clean Heat initiatives,  
18 residential safety and emissions mitigation.

19 Q. What is your recommendation regarding the  
20 Companies' participation in Internal  
21 Projects/UTD, including GTI/UTD?

22 A. We acknowledge that NYSEG's participation in  
23 GTI/UTD provides indirect benefits to  
24 ratepayers. The Companies state in their

1 response to DPS-904 that not participating in  
2 this program risks falling behind and missing  
3 opportunities for improvement. However, we  
4 argue that this expense, as well as the Internal  
5 Projects/UTD budget in its entirety, is  
6 discretionary and not vital for operating a gas  
7 utility during the Rate Year. Therefore, we  
8 recommend a pause in participation in the  
9 Internal Projects/UTD program in the Rate year  
10 for both Companies.

11 Q. Does the Panel recommend any additional budget  
12 changes to the Research and Development program?

13 A. Yes. With the affordability concerns outlined  
14 in the Staff Policy Panel testimony and the  
15 discretionary nature of the Research and  
16 Development programs, we also recommend a pause  
17 in participation in the Millenium program in the  
18 Rate Year for both Companies. Additionally, we  
19 recommend adjusting the Companies' NYSERDA  
20 budgets to reflect the inflation rate  
21 recommended by the Staff Forecasting Panel. Our  
22 total recommended budgets for Research and  
23 Development in the Rate Year are shown in  
24 Exhibit\_\_ (SGIOP-3).

1 Gas Reconcilable Programs

2 Q. What are gas reconcilable programs?

3 A. These are a selection of gas programs that have  
4 a symmetrical reconciliation of annual budgets.  
5 They include fire department outreach, damage  
6 prevention programs, outside and inside meter  
7 inspections, and the leak survey program.

8 Q. Do you recommend adjustments to any of these  
9 programs?

10 A. Yes, we recommend adjustments to the fire  
11 department outreach, damage prevention and leak  
12 survey programs.

13 Q. Describe the Fire Department Outreach Program.

14 A. According to the Companies' response to DPS-932,  
15 the Fire Department Outreach Program provides  
16 in-person training sessions on natural gas  
17 safety to fire departments and emergency  
18 responders.

19 Q. Why is this program needed?

20 A. As stated in the Companies' response to DPS-932,  
21 local fire departments are often first to  
22 respond to the scene and may not be aware of  
23 natural gas hazards or safety procedures to  
24 secure a scene before the Companies' crews

1 arrive.

2 Q. What are the benefits to ratepayers from this  
3 program?

4 A. As stated in the Companies' response to DPS-932,  
5 the ratepayers will have faster and safer  
6 emergency response, reducing risk of injury or  
7 property damage.

8 Q. Is this a new program, or existing program?

9 A. This is an existing program.

10 Q. Describe how the Companies developed the Rate  
11 Year operating expenses for this program.

12 A. The Companies propose \$1,000 per fire  
13 department. NYSEG proposes a budget of \$72,000  
14 to cover 72 fire departments. RG&E proposes a  
15 budget of \$24,000 to cover 24 fire departments.

16 Q. Do you recommend changes to the proposed  
17 budgets?

18 A. Yes. RG&E's proposed Rate Year budget remains  
19 consistent to prior years. NYSEG's proposed  
20 Rate Year budget assumes 72 fire department  
21 trainings, an increase from 42 fire departments  
22 in the historic test year. Therefore, we agree  
23 with the Companies' forecast for RG&E but  
24 recommend a budget of \$42,000 for NYSEG to align

1 with historical performance.

2 Q. Describe the Enhanced Damage Prevention  
3 Vehicles, or DPV, Program.

4 A. As stated in the Companies' response to DPS-  
5 1240, this program includes 22 DPV drivers, two  
6 supervisors and one Dispatcher for each Company.  
7 These DPV drivers survey the Companies' service  
8 territories to inspect for potential third party  
9 damages to the gas distribution system and  
10 educate contractors at worksites.

11 Q. Why is this program needed?

12 A. DPV drivers are trained to prevent third-party  
13 errors such as mismarks and damages that would  
14 affect customer service and safety. DPV drivers  
15 identified a combined 353 third-party violations  
16 in 2024. In addition, DPV drivers have reduced  
17 damages in large-scope, high-risk fiber  
18 installation projects from 23 in 2022 to 11 in  
19 2023 and four in 2024.

20 Q. What are the benefits to ratepayers from this  
21 program?

22 A. There are four main benefits to ratepayers:  
23 fewer service disruptions, lower repair and  
24 emergency response costs, improved public

1 safety, and stronger compliance with state  
2 regulations.

3 Q. Is this a new program, or existing program?

4 A. This is an existing program.

5 Q. Describe how the Companies developed the Rate  
6 Year operating expenses for this program.

7 A. The Companies state in their workpapers NG-RRP-  
8 2-WP-03a-MY and RG-RRP-2-WP-03a-MY, provided in  
9 response to DPS-263, that the proposed program  
10 costs are based on historic test year operating  
11 expenses with an anticipated 10 percent increase  
12 in contract cost.

13 Q. Why did the Companies forecast a ten percent  
14 increase in contract cost?

15 A. The Companies are expanding the number of DPV  
16 drivers with Operator Qualifications, or OQs, in  
17 locating from 50 percent in 2024 to 75 percent  
18 in 2025 and 2026, respectively. As stated in  
19 the Companies' response to DPS-1240, they  
20 propose to expand the number of DPV drivers with  
21 OQs to continue to support damage prevention.  
22 DPV drivers with OQs audit locators and work  
23 with excavators if there is a question with the  
24 locate, providing better quality assurance of

1 locates and the process. The Companies are  
2 proposing converting five DPV drivers per  
3 Company to DPV drivers with OQs. DPV drivers  
4 with OQs have an hourly rate **BEGIN CONFIDENTIAL**  
5 **INFORMATION < [REDACTED] >END CONFIDENTIAL**  
6 **INFORMATION** per hour higher than standard DPV  
7 drivers. This equates to an increase of **BEGIN**  
8 **CONFIDENTIAL INFORMATION < [REDACTED] > END**  
9 **CONFIDENTIAL INFORMATION** per year for each  
10 Company.

11 Q. Do the Companies hire an outside contractor to  
12 perform this work, or is the work performed with  
13 its internal workforce?

14 A. The Companies hire an outside contractor to  
15 perform this work.

16 Q. Did the Companies use a competitive bidding  
17 process when hiring an outside contractor for  
18 this program?

19 A. Yes. The Companies used a competitive bidding  
20 process, with eight vendors bidding on the work.

21 Q. Do the Companies anticipate any changes to this  
22 program in the future?

23 A. The Companies are anticipating a 10 percent  
24 increase in program costs due to contract costs,

1 but no other changes.

2 Q. Do you agree with the proposed program costs in  
3 the Rate Year?

4 A. No.

5 Q. Please explain.

6 A. The Companies stated in response to DPS-932 that  
7 the primary reason for the 10 percent increase  
8 in program cost was due to expanding the number  
9 of DPV drivers with OQs. As described in the  
10 Companies' response to DPS-1240, the increase in  
11 DPV drivers with OQs will equate to **BEGIN**

12 **CONFIDENTIAL INFORMATION** < [REDACTED] > **END**

13 **CONFIDENTIAL INFORMATION** in the Rate Year for  
14 each Company. However, the 10 percent increase  
15 in program costs in the Rate Year increases the  
16 expense at NYSEG by \$242,164 and RG&E by  
17 \$213,258, **BEGIN CONFIDENTIAL INFORMATION** < [REDACTED]

18 [REDACTED] > **END CONFIDENTIAL**

19 **INFORMATION** increase from OQ drivers.

20 Q. Do you recommend any changes to the program  
21 budget?

22 A. We recommend applying a **BEGIN CONFIDENTIAL**  
23 **INFORMATION** < [REDACTED] > **END CONFIDENTIAL**

24 increase to the program budget for each Company.

1           Given the information we have available, our  
2           understanding is that the increase in OQ drivers  
3           is the only identified increase to the program.  
4           Our recommended budget is shown in  
5           Exhibit\_\_ (SGIOP-3).

6   Q.   Describe the non-mandated Leak Survey Program.

7   A.   The Companies are proposing to conduct a non-  
8       mandated leak survey of two-thirds of its gas  
9       system each year, starting in the Rate Year.  
10       This program also includes earthquake surveys,  
11       material issues surveys, flooding surveys, and  
12       surveys included in system maintenance or  
13       upgrades.

14   Q.   Why is this program needed?

15   A.   This program will locate hazardous or high  
16       emitting leaks that would not have been detected  
17       until a future compliance survey.

18   Q.   Is this a new program, or existing program?

19   A.   This is an existing program.

20   Q.   Describe how the Companies developed the Rate  
21       Year operating expenses for this program.

22   A.   The Companies state in their workpapers NG-RRP-  
23       2-WP-03a-MY and RG-RRP-2-WP-03a-MY, provided in  
24       response to DPS-263, that the program costs were

1 developed using the Rate Year 3 funding levels  
2 of \$725,000 at NYSEG and \$491,000 at RG&E  
3 approved by the 2023 Rate Order, adjusted for  
4 inflation.

5 Q. Explain why the historic test year spending for  
6 this program is \$131,000 at NYSEG and \$26,000 at  
7 RG&E, significantly lower than the Rate Year 3  
8 funding levels approved by the 2023 Rate Order.

9 A. The Companies state in their response to DPS-932  
10 that they were focused on completing mandated  
11 work during the historic test year, specifically  
12 the Inside Service Line Inspection program. As  
13 a result, spending for this program was lower  
14 than budgeted and amounts not spent are returned  
15 to customers.

16 Q. What mileages of inspection have the Companies  
17 been able to perform historically?

18 A. As the Companies stated in their response to  
19 DPS-1152, the most mileage NYSEG inspected in a  
20 single year was 2,612 miles in 2020, and they  
21 only inspected 72 miles in 2024, for a total of  
22 6,161 miles from 2020 through 2024. The most  
23 miles RG&E inspected in a single year was 792  
24 miles in 2023, while they inspected zero miles

1 in 2024, for a total of 1,952 miles from 2020  
2 through 2024.

3 Q. What mileage of inspection do the Companies  
4 anticipate performing during the Rate Year?

5 A. As stated in their response to DPS-1152, the  
6 Companies plan to inspect 2,989 miles for NYSEG  
7 and 3,306 miles for RG&E.

8 Q. How do the Companies justify the increase in  
9 inspection mileage?

10 A. The Companies are proposing to increase the  
11 mileage of inspection significantly from  
12 historical levels due to contractor availability  
13 as well as using Advanced Mobile Leak Detection,  
14 or AMLD.

15 Q. Describe how the Companies will increase  
16 inspection mileage using AMLD.

17 A. The Companies are evaluating the use of AMLD for  
18 parts of this program. AMLD units will allow  
19 the Companies to locate pipeline leaks at  
20 greater distances, decreasing surveying time.  
21 In addition, only one driver is required per  
22 AMLD unit, which would allow the Companies to  
23 run this program alongside mandated surveys,  
24 increasing surveyed mileage.

1 Q. Do you agree that the Companies can achieve the  
2 mileage of leak survey forecasted for the Rate  
3 Year?

4 A. No. NYSEG completed approximately 87 percent of  
5 the proposed Rate Year mileage target in 2020,  
6 but has not completed that much in a single year  
7 since. RG&E has not completed near the amount  
8 of their planned Rate Year mileage in the past  
9 five years combined, with their highest mileage  
10 year at less than 25 percent of the planned Rate  
11 Year mileage.

12 Q. What is your recommended Rate Year budget for  
13 non-mandated leak survey?

14 A. We recommend budgets based on the historic test  
15 year's mileage performed by each Company, and  
16 the cost per mile calculated from the Companies'  
17 proposed Rate Year mileage and budgets in  
18 workpapers NG-RRP-2-WP-03a-MY and RG-RRP-2-WP-  
19 03a-MY, provided in response to DPS-263. For  
20 NYSEG we recommend a budget of \$18,629 to  
21 complete 72 miles of non-mandated leak survey.  
22 For RG&E we do not recommend a budget for non-  
23 mandated leak survey in the Rate Year, as they  
24 completed zero miles of non-mandated leak survey

1 in the historic test year.

2 Q. Do the Companies propose to move any Gas  
3 Reconcilable Program budgets to other operating  
4 expense line items?

5 A. Yes. The Companies propose moving Fire  
6 Department Outreach, Damage Prevention, and  
7 Corrosion Control to Outside Services.

8 Q. Do you agree with the proposed move?

9 A. No. Gas Reconcilable Programs has a downward  
10 only reconciliation, meaning that if the  
11 Companies underspend the forecast budgets that  
12 customers are reconciled to recoup the  
13 difference. Outside Services does not have a  
14 reconciliation; therefore, moving these line  
15 items from Gas Reconcilable Programs removes  
16 that customer protection. Therefore, we  
17 recommend maintaining these line items within  
18 the Gas Reconcilable Programs budget and subject  
19 to a downward only reconciliation.

20 Q. Do the Companies propose to move other Operating  
21 Expenses to Outside Services?

22 A. Yes. The Companies propose moving three line  
23 items from Incremental Maintenance: Public  
24 Awareness, Exposed Piping on Bridges, and QA/QC

1           Excavations/Field Support.

2    Q.    Do you agree with the proposed move?

3    A.    No.  As described above, Outside Services does  
4           not have a reconciliation, and moving these  
5           items would remove the customer protection.  
6           Therefore, we recommend removing these line  
7           items from Outside Services and adding them to  
8           the Gas Reconcilable Programs budget, subject to  
9           a downward only reconciliation.

10   Q.    What is your recommended total Gas Reconcilable  
11          Programs budget for each Company?

12   A.    Our recommended budgets are shown in  
13          Exhibit\_\_ (SGIOP-3).

14   Gas Pipeline Integrity

15   Q.    Describe the Gas Pipeline Integrity Programs.

16   A.    The Companies have multiple programs dedicated  
17          to maintaining the safety and reliability of gas  
18          pipelines.  There are five sub-topics within the  
19          Gas Pipeline Integrity Program including Program  
20          Administration, Integrity Management Program, or  
21          IMP, Mandated and Scheduled Assessments,  
22          Pipeline and Hazardous Materials Safety  
23          Administration, or PHMSA, Mega Rule, Pipeline  
24          Rehabilitation Program, and Prevailing Wage.

1 Q. Briefly summarize the specific proposals for  
2 this program.

3 A. Improvements to the Integrity Management Program  
4 Geospatial Database software to comply with the  
5 PHMSA Mega Rule, or Mega Rule, requirements and  
6 implementing a Standard Data Model; developing a  
7 new Transmission Integrity Management Program,  
8 or TIMP, Risk Model; Robotic In-Line Inspection  
9 program, or Robotic ILI, which will use Robotic  
10 ILI technology to inspect an increased length of  
11 pipeline as mandated by the Mega Rule; Guided  
12 Wave Assessments; creation of an MAOP  
13 Reconfirmation database; and projects to  
14 remediate anomalies on high-pressure or  
15 transmission pipelines.

16 Q. Do you recommend any adjustments to the Gas  
17 Pipeline Integrity program?

18 A. Yes, we recommend updating the budgets to  
19 reflect the inflation rate recommended by the  
20 Staff Sales Forecasting Panel. Our recommended  
21 Rate Year budgets are shown in Exhibit\_\_ (SGIOP-  
22 3).

23 NPA General Costs

24 Q. Describe the Lansing NPA Program.

1 A. As described previously in our testimony, this  
2 program implements NPAs to replace NYSEG's  
3 natural gas compressor stations in Lansing.  
4 There are five projects within the Lansing NPA  
5 Program portfolio: Proposal One, Lansing  
6 Residential Heat Pumps; Proposal Two, Lansing  
7 Single Commercial Ground Source Heat Pump;  
8 Proposal Three, Lansing Community Ground Source  
9 Heat Pump; Proposal Five, Lansing Energy  
10 Efficiency at Two Public Authority Buildings;  
11 and Proposal Sixteen, Lansing Education and  
12 Outreach Program.

13 Q. Why is this program needed?

14 A. This program will improve reliability on very  
15 cold days in the Lansing area and reduce natural  
16 gas demand. The Company is not currently able  
17 to maintain 50 percent MAOP during peak day  
18 conditions and has a moratorium on new gas  
19 service.

20 Q. Is this a new program, or existing program?

21 A. This is an existing program. In June 2021, the  
22 2021 NPA Order directed the Company to implement  
23 a seven-project NPA portfolio. The developers  
24 for Proposals Seven and Eight withdrew their

1 proposals, resulting in the five project NPA  
2 portfolio proposed in this program.

3 Q. Describe how the Companies developed the Rate  
4 Year operating expenses for this program.

5 A. The Company included \$4,508,182 in Rate Year  
6 costs associated with the NPA portfolio in  
7 Lansing. The response to DPS-968 indicates  
8 those costs include \$2.1 million for the Lansing  
9 Residential Heat Pumps, \$2.2 million for the  
10 Lansing Community Ground Source Heat Pump and  
11 \$79,609 for the Lansing Education and Outreach  
12 Program.

13 Q. What is the cost of the entire approved NPA  
14 portfolio?

15 A. Approximately \$8.8 million.

16 Q. What method did the Commission direct for cost  
17 recovery of the NPA portfolio?

18 A. Appendix HH of the terms of the Joint Proposal  
19 adopted in the 2023 Rate Order states that NPA  
20 solutions should be amortized over the used and  
21 useful life of the infrastructure involved in  
22 the project, or NPAs without a clear measurable  
23 amortization period should be amortized over a  
24 20-year period.

1 Q. Did NYSEG amortize the proposed Rate Year costs?

2 A. As stated in the Companies' response to DPS-  
3 1380, NYSEG did not amortize these costs and is  
4 proposing immediate recovery of these costs.  
5 The Company states that faster recovery of these  
6 costs will improve credit metrics.

7 Q. Do you agree with the Rate Year budget of  
8 \$4,508,182?

9 A. No. We recommend amortizing those costs as  
10 directed by the 2021 NPA Order. The response to  
11 DPS-1380 provides the useful life for equipment  
12 installed under each project. In general, the  
13 Lansing Residential Heat Pumps and the Lansing  
14 Community Ground Source Heat Pumps equipment  
15 lists have an approximate average age of 20  
16 years, so we recommend that amortization period.  
17 As the Lansing Education and Outreach Program  
18 does not have a measurable useful life, we  
19 recommend a 20-year amortization. Our  
20 recommended Rate Year expense is shown in  
21 Exhibit\_\_ (SGIOP-3).

22 Incremental Maintenance

23 Q. Provide a description of the work performed  
24 under this program.

- 1 A. The Incremental Maintenance program's projects  
2 include Wildfire Mitigation, residential methane  
3 detectors, or RMDs, Compliance - AI Solution,  
4 and Pipeline Safety Management System, or PSMS.  
5 This line item is intended to capture new  
6 programs and is subject to a downward only  
7 reconciliation to protect customers, as new  
8 program budgets are more difficult to forecast  
9 without historical data.
- 10 Q. Provide a description of the Wildfire Mitigation  
11 program.
- 12 A. Beginning on page 125 of the Gas Operations  
13 Panel testimony, the Companies describe the  
14 proposal to install a firebreak around selected  
15 gate stations to protect from potential  
16 wildfires.
- 17 Q. What are the firebreaks the Companies are  
18 proposing?
- 19 A. The firebreaks would be outside the fence line  
20 of the gate station, between two and fifteen  
21 feet wide, where vegetation is removed, and  
22 gravel is installed to create a barrier and stop  
23 potential wildfires from coming into direct  
24 contact with structures.

1 Q. How many of the Companies' gate stations require  
2 Wildfire Mitigation?

3 A. The Companies indicate there are three gate  
4 stations for RG&E and 25 gate stations for NYSEG  
5 that have been identified for the program. The  
6 Companies proposed wildfire mitigation for four  
7 NYSEG gate stations and one RG&E gate station in  
8 the Rate Year.

9 Q. Why is this program needed?

10 A. As stated on page 125 of the Gas Operations  
11 Panel testimony, the Companies conducted an  
12 analysis identifying gate stations with exposure  
13 to brush, tall grass, and other combustibles.  
14 This project would protect the gate stations  
15 from potential wildfires.

16 Q. How do the Companies develop the Rate Year  
17 operating expenses for this program?

18 A. As stated on page 127 of the Gas Operations  
19 Panel testimony, the cost is estimated to be  
20 \$61,715 per location to install wildfire  
21 mitigation. The Companies plan to complete five  
22 stations in the Rate Year.

23 Q. Have changes been made to the Wildfire  
24 Mitigation program since the Companies' original

1 testimony?

2 A. Yes. In the Companies' corrections and updates,  
3 they removed the one gate station for RG&E and  
4 added an additional gate station to NYSEG.

5 Q. Do you agree with the proposed budgets for the  
6 Wildfire Mitigation program?

7 A. No. With the affordability concerns outlined by  
8 the Staff Policy Panel, we argue that starting a  
9 new program to mitigate against wildfires in the  
10 Rate Year should be avoided. We recommend that  
11 the Companies continue to develop and assess  
12 more cost-effective strategies for wildfire  
13 mitigation.

14 Q. Provide a description of the Residential Methane  
15 Detectors program.

16 A. The RMD program distributes RMDs to customers  
17 and conducts gas safety outreach and education.  
18 The Companies are proposing a change to this  
19 existing program by deploying RMDs that are  
20 connected to the AMI system. The Companies  
21 propose a temporary hold on the program,  
22 resulting in no RMDs being distributed and a  
23 budget of zero dollars in the Rate Year, until  
24 the connected RMDs compatible with their AMI

1 network are readily available after the Rate  
2 Year.

3 Q. Do you recommend any adjustments to the  
4 Incremental Maintenance program?

5 A. Yes. First, concerning RMDs. The Companies do  
6 not propose any Rate Year expenses for RMDs,  
7 either the existing units or the proposed AMI-  
8 connected units. The Companies propose \$250,000  
9 in Rate Year 2, or the 12 months ending April  
10 30, 2028, as estimated costs for updates to  
11 administrative enhancements and a base pilot.  
12 In Rate Year 3, or the 12 months ending April  
13 30, 2029, the Companies propose 2,500 units at  
14 \$1,100 per installed unit for a total of  
15 \$2,750,000. We clarify that we have no specific  
16 adjustments as there are no proposed expenses  
17 forecast in the Rate Year. However, note the  
18 response to DPS-385 indicates that the  
19 installation costs associated with the AMI-  
20 connected units is forecast by the Companies to  
21 be \$740 per unit. We recommend that the  
22 Companies refine this estimate and note that we  
23 strongly disagree that the installation of a  
24 single AMI-connected RMD would cost \$740. We

1           also recommend that the Companies explore units  
2           that could be self-installed by customers, with  
3           verification for the installation, to reduce  
4           installation costs.

5   Q.   Do you have any other recommended adjustments to  
6       Incremental Maintenance?

7   A.   Yes.  We recommend correcting RG&E's Compliance  
8       - AI Solution project cost to \$13,000 for the  
9       Rate Year, removing the Company's proposed  
10      inflation to match NYSEG's project cost.  This  
11      brings RG&E's Incremental Maintenance budget to  
12      \$113,000 for the Rate Year.

13   Q.   Do the Companies propose to move any Incremental  
14      Maintenance budgets to Base O&M?

15   A.   Yes.  The Companies propose to move 12 NYSEG  
16      projects and 17 RG&E projects to Base O&M.

17   Q.   Are you in support of the proposed move?

18   A.   No.  Like the Companies' proposal to move  
19      certain programs out of Gas Reconcilable  
20      Programs to Outside Services, moving these  
21      programs to Outside Services would mean they are  
22      no longer subject to a downward only  
23      reconciliation.  Therefore, we recommend moving  
24      these Base O&M programs to Gas Reconcilable

1 Programs instead.

2 Gas LTP

3 Q. What are Gas Long-Term Plans, or LTPs?

4 A. On May 12, 2022, the Commission issued its Order  
5 Adopting Gas System Planning Process, or Gas  
6 Planning Order, in Case 20-G-0131 requiring gas  
7 utilities in New York State to file LTPs on a  
8 three-year cycle. In addition, the Companies  
9 must file annual updates on May 31 of years two  
10 and three of the three-year cycle.

11 Q. Describe how the Company developed its proposed  
12 costs associated with its LTPs.

13 A. As stated in the workpapers NG-RRP-2-WP-10-MY  
14 and RG-RRP-2-WP-10-MY, provided in response to  
15 DPS-263, the Companies include costs associated  
16 with LTP filings and annual updates, as directed  
17 by the Gas Planning Order.

18 Q. Is this a new program, or existing program?

19 A. This is a new operating expense line item. The  
20 Companies filed their most recent LTP on October  
21 2, 2023, and their annual update on May 29,  
22 2025, in Case 23-G-0437. The Commission also  
23 issued an Order Regarding Long-Term Natural Gas  
24 Plan and Directing Further Actions on January

1           23, 2025, in Case 23-G-0437, the Further Action  
2           Order. Previously, the Companies have deferred  
3           costs associated with their LTP filings for  
4           future recovery.

5   Q.    Explain the increased operating expenses for  
6           Rate Years 1 and 3 compared to Rate Years 2, 4,  
7           and 5.

8   A.    The Companies are scheduled to file an LTP in  
9           Rate Year 3, which includes additional costs  
10          compared to the annual update filings.

11   Q.    Are there any FTEs associated with this program?

12   A.    Yes. The Companies propose one FTE, a program  
13          manager, to coordinate its LTP filings.

14   Q.    What are the costs associated with the annual  
15          update?

16   A.    As stated in the Companies' response to DPS-  
17          1150, they are proposing external costs of  
18          \$95,000 at each Company for the annual update  
19          costs in the Rate Year.

20   Q.    What are the costs associated with the three-  
21          year full LTP filing?

22   A.    As stated in response to DPS-1150, the Companies  
23          propose external costs of \$515,409 at each  
24          Company for the full LTP filing in RY3.

1 Q. Have the Companies hired a consultant for the  
2 LTP filing at this time?

3 A. No.

4 Q. Will the Companies use a competitive bidding  
5 process when hiring a consultant for the LTP  
6 filing?

7 A. Yes, the Companies will submit an RFP to select  
8 a consultant for work related to the Annual  
9 Updates and LTP filings.

10 Q. Which parts of the filing will the Companies  
11 contract out, and which parts will be completed  
12 internally?

13 A. The Companies state in their response to DPS-767  
14 that they will contract out the quantitative  
15 technical analyses for the Annual Updates and  
16 LTP filings to external consultants. This will  
17 include Benefit-Cost Analysis calculations,  
18 scenario modeling, and updated bill impact  
19 analysis. The proposed incremental FTE will be  
20 responsible for the non-quantitative analysis  
21 tasks in the Annual Updates and LTP filings.  
22 The FTE will coordinate activities consistent  
23 with prior filings, coordinate the tracking of  
24 internal progress, and assist in identifying and

1 describing future initiatives.

2 Q. What are the costs associated with the parts of  
3 the filing that will be contracted out?

4 A. As stated in response to DPS-1150, the Companies  
5 are proposing \$95,000 for NYSEG and \$95,000 for  
6 RG&E for the Annual Update costs in the Rate  
7 Year, as well as \$60,000 for NYSEG and \$60,000  
8 for RG&E for any Further Action Order support  
9 that may be issued. The Further Action Order  
10 support costs are not reflected in the  
11 Companies' initial testimony nor in the  
12 Companies' corrections and updates filing.

13 Q. What are the costs associated with the parts of  
14 the filing that will be done internally?

15 A. The Companies propose internal incremental  
16 expenses consisting of an average base salary of  
17 \$111,000, plus standard overhead costs for the  
18 proposed incremental FTE. The average base  
19 salary is calculated as the midpoint of the  
20 identified market-competitive salary range.

21 Q. Do you support the hiring of the program manager  
22 to support LTP filings?

23 A. No. We argue that this work can be incorporated  
24 into the Companies' current workload. Further,

1           most of the work will continue to be performed  
2           by external contractors. The Companies have  
3           already made an initial LTP filing without this  
4           incremental position, and future filings should  
5           be more streamlined after the initial filing.

6    Q.    What further actions did the Commission direct  
7           in the Further Action Order?

8    A.    In the Further Action Order, the Companies were  
9           directed to develop a demand response program,  
10           submit a report on the Companies' capacity  
11           reserve margin calculation, conduct a  
12           stakeholder technical conference exploring  
13           strategic decommissioning criteria and submit a  
14           report, submit a report on the substantiation of  
15           maximum allowable operating pressure in certain  
16           pipe segments, and meet with large commercial  
17           and industrial customers regarding the use of  
18           RNG and hydrogen and file a report. The  
19           Companies filed reports regarding the actions in  
20           Case 23-G-0437 in May and July of 2025.

21   Q.    Did the Companies provide details or proposals  
22           concerning these actions in this rate filing?

23   A.    The Companies propose internal incremental  
24           expenses to support one additional FTE employee

1 and external incremental expenses for the Annual  
2 Updates and the next LTP filing totaling  
3 \$190,000 for the Rate Year. In addition, the  
4 Companies propose to defer any Climate  
5 Leadership and Community Protection Act-related  
6 incremental expenses and fees that are not  
7 included in base rates subject to symmetrical  
8 reconciliation.

9 Q. Do you agree with the costs related to LTP  
10 filings proposed by the Companies?

11 A. Yes, except for the incremental FTE requested,  
12 we agree with the proposed operating expenses  
13 for the Rate Year. However, we disagree with  
14 the need for a continued deferral for LTP costs.  
15 The Companies have forecast costs in the Rate  
16 Year; therefore, with recovery through base  
17 rates no deferral is necessary.

18 FTEs

19 Q. Which titles of the Companies' proposed  
20 incremental FTEs did you review?

21 A. The titles and our recommended adjustments are  
22 shown in Exhibit\_\_ (SGIOP-4). We will provide  
23 justification for any recommended adjustments.

24 Q. What is the proposed Environmental and

1           Permitting Specialist at NYSEG?

2    A.    This FTE would provide environmental compliance  
3           and permitting expertise and oversight for  
4           NYSEG's operations and capital projects. The  
5           full job description is provided in the response  
6           to DPS-560.

7    Q.    Do the Companies currently have an employee  
8           handling this responsibility?

9    A.    Yes. Attachment 16 to DPS-560 explains that  
10           currently these tasks are being performed by an  
11           environmental program manager who oversees both  
12           NYSEG and RG&E.

13   Q.    Do you recommend that the Company needs an  
14           additional FTE at NYSEG to complete this  
15           workload?

16   A.    No. Currently this workload is completed by a  
17           single employee for both Companies, and the  
18           response to DPS-560 does not justify the need  
19           for an extra FTE.

20   Q.    Are there any other incremental FTEs that would  
21           have job responsibilities overlapping with the  
22           current environmental program manager who  
23           oversees both NYSEG and RG&E?

24   A.    Yes, the proposed Program Manager for

1 Environmental Permitting.

2 Q. What is your recommendation for this FTE?

3 A. Similarly, we recommend this FTE is unnecessary  
4 as this workload is being completed by an  
5 existing employee.

6 Q. What is the proposed Program Manager for  
7 Emergency Management?

8 A. The Companies propose one FTE, with time split  
9 evenly between the two Companies, to focus on  
10 improving the Companies' ability to respond to  
11 natural gas emergencies. The position is  
12 described beginning on page 94 of the Gas  
13 Operations Panel testimony, as well as in the  
14 response to DPS-560, Attachments 10 and 19.

15 Q. How are these responsibilities currently being  
16 fulfilled?

17 A. As stated in the response to DPS-560, Attachment  
18 19, these responsibilities are being supported  
19 by a single program manager within the  
20 Companies' emergency management department.

21 Q. What is your recommendation concerning this FTE?

22 A. We recommend that this additional FTE is  
23 unnecessary. Currently, the work is being  
24 performed by a program manager and can continue

1 to be performed by this employee.

2 Q. What is the proposed Program Manager within  
3 Process and Technology?

4 A. The Companies propose one FTE at NYSEG in the  
5 Rate Year. As described in the response to DPS-  
6 560, Attachments 9 and 18, this FTE would  
7 analyze gas operations and develop and implement  
8 system process improves to improve operational  
9 performance.

10 Q. How are these responsibilities currently being  
11 fulfilled?

12 A. As stated in the response to DPS-560, Attachment  
13 18, these process improvement tasks are being  
14 carried out in a decentralized manner by  
15 existing employees.

16 Q. What is your recommendation concerning this FTE?

17 A. We recommend that this additional FTE is not  
18 essential for gas operations. Existing  
19 employees should continue to provide process  
20 improvements where possible.

21 Tariff Changes

22 Q. Do the Companies propose any gas tariff changes  
23 related to dual-fuel requirements?

24 A. Yes. These changes are described beginning on

1 page 69 of the Revenue Allocation and Rate  
2 Design Panel's testimony. These changes would  
3 remove the dual-fuel requirement for large gas  
4 customers receiving firm service. The Companies  
5 state this change is reasonable because these  
6 customers are not interruptible and therefore do  
7 not need this capability. This requirement  
8 imposes additional costs on these customers for  
9 an alternate fuel supply in case of  
10 interruption, when the Companies are planning to  
11 serve these customers as firm customers without  
12 interruption.

13 Q. Do you agree with the proposed changes?

14 A. Yes.

15 Gas Policy and Supply Issues

16 Renewable Natural Gas Interconnections

17 Q. Define RNG.

18 A. RNG is a biogas generated from the decomposition  
19 or gasification of renewable biomass. The  
20 renewable biomass can originate from landfills,  
21 wastewater treatment plants, farms, and other  
22 sites capable of converting organic matter into  
23 biogas. The biogas is then refined to remove  
24 non-methane compounds or particulate and

1 enriched to meet gas pipeline quality standards.  
2 Because RNG is created as a byproduct of  
3 decomposition, RNG is virtually inexhaustible  
4 over time but limited in the amount of energy  
5 that is available at any one point in time.

6 Q. What are the benefits of RNG?

7 A. RNG sources could provide additional localized  
8 supply and pressure support, improving  
9 reliability within the distribution system. RNG  
10 interconnections can also directly support the  
11 reliability of gas connections for customers  
12 because doing so can increase both the amount of  
13 gas available for the Companies' capacity  
14 requirements and the diversity of the Companies'  
15 gas resource portfolio.

16 Q. Are there any ratepayer risks associated with  
17 RNG?

18 A. RNG interconnections pose potential economic and  
19 operational risks to ratepayers. The economic  
20 uncertainty of the environmental credits and tax  
21 incentives, which producers often utilize for  
22 funding, could prove detrimental to RNG  
23 production in the absence of such incentives.  
24 If the availability of funding from these

1 sources changes in the future, producers risk  
2 failing to meet facility costs, which may result  
3 in a slowdown or shutdown of an RNG plant.  
4 Operationally, RNG must meet the same gas  
5 quality standards as traditional sources. If  
6 the components of the biogas change, such as  
7 increased moisture or other constituents, it  
8 could force the facility to temporarily shut  
9 down. These two risks could result in either a  
10 stranded interconnection asset or a decreased  
11 flow of RNG into the distribution system, which  
12 would fail to meet supply needs.

13 Q. What are the Companies proposing concerning RNG?

14 A. The Companies are considering, as described on  
15 page 35 of the Electric and Gas Supply and  
16 Interconnections Panel, or EGSIP, procuring RNG  
17 from out-of-state locations to meet RNG volumes  
18 outlined in the LTP.

19 Q. What concerns do you have with this proposal?

20 A. We are concerned with this proposal considering  
21 its out-of-state origins. As outlined by our  
22 testimony, RNG is recognized as a valuable  
23 resource to provide on-system pressure support  
24 through local interconnections directly on the

1 Companies distribution system. However, the  
2 procurement of such gas from out-of-state  
3 entities limits the on-system benefits outlined.  
4 This procurement is particularly concerning if  
5 the Company pays a premium for RNG over  
6 traditional gas supply. Any RNG purchased  
7 outside of the Companies' service territories  
8 should be equal to or less than the weighted  
9 average cost of traditional gas since it does  
10 not provide the same on-system supply benefits  
11 as a local interconnection does.

12 Q. Do the Companies outline any other requests  
13 related to RNG in their filings?

14 A. Yes, the Companies state on page 37 of the EGSIP  
15 their intent to purchase environmental credits  
16 associated with RNG supply on behalf of  
17 commodity customers. The Companies propose to  
18 purchase environmental credits throughout the  
19 rate years as follows: 1) up to 200,000 Dths of  
20 RNG in the Rate Year; 2) up to 220,000 Dths of  
21 RNG in Rate Year 2; 3) up to 245,000 Dths of RNG  
22 in Rate Year 3; 4) up to 270,000 Dths of RNG in  
23 Rate Year 4; and 5) up to 300,000 Dths of RNG in  
24 Rate Year 5.

1 Q. What justification do the Companies provide for  
2 the purchase of RNG environmental attributes?

3 A. The Companies claim on page 37 of the EGSIP  
4 direct testimony that the purchase of  
5 environmental credits will maximize GHG  
6 emissions reductions to align with the LTP.  
7 Further, the Companies state on page 38 of the  
8 EGSIP direct testimony that environmental credit  
9 purchasing would encourage RNG developers to  
10 invest in the Companies' service territories and  
11 increase the Companies' GHG emissions  
12 reductions.

13 Q. Do you agree with the Companies' proposals?

14 A. No, we do not agree with the Companies proposals  
15 for a variety of reasons. To start, there is no  
16 environmental credit market within the State,  
17 nor any endorsed by the Commission or other  
18 State entity. Therefore, the purchase of  
19 environmental credits, and any emissions-related  
20 benefits claimed by them, are not recognized.  
21 Regarding the Companies' claim that  
22 environmental credits will encourage RNG  
23 developers to develop in the Companies' service  
24 territories, it should be made clear that

1 ratepayers will not be responsible for  
2 subsidizing RNG interconnections or developers  
3 in any direct or indirect manner. As described  
4 previously in our testimony, there are a variety  
5 of risks associated with RNG interconnections,  
6 and subsidizing these interconnections on behalf  
7 of ratepayers may encourage riskier and  
8 financially unstable companies to invest in  
9 development within the Companies' service  
10 territories due to the promise of environmental  
11 credits.

12 Q. What do you recommend regarding the purchase of  
13 these attributes?

14 A. We recommend the Companies do not receive cost  
15 recovery of RNG environmental attribute  
16 purchasing outlined in their proposal.  
17 Considering the lack of an environmental  
18 attribute market in New York State, and the need  
19 to protect rate payers from funding RNG  
20 interconnections directly or indirectly, there  
21 is no justification for why the Companies should  
22 purchase such credits at rate payer expense.

23 Differentiated Natural Gas

24 Q. Define differentiated natural gas.

1 A. DNG, previously referred to as responsibly  
2 sourced natural gas or CNG, is natural gas  
3 derived in a manner that is purported to have  
4 decreased environmental impacts and lower  
5 greenhouse gas emissions. Certification is  
6 provided by a third-party company specialized in  
7 emissions mitigation through qualitative or  
8 quantitative practices. Compared to traditional  
9 natural gas, DNG is purported to be a lower  
10 carbon alternative due to these practices.

11 Q. What are the Companies proposing regarding DNG?

12 A. The Companies propose, on pages 44 through 48 of  
13 the EGSIP direct testimony, to make permanent  
14 the CNG pilot, which will be referred to as the  
15 differentiated gas pilot program, which was  
16 approved by the Commission in the 2023 Rate  
17 Order. Alongside the Companies' request to make  
18 this pilot program permanent, they are also  
19 requesting that the budget for this program be  
20 increased from a \$250,000 annual cap to  
21 \$300,000.

22 Q. Do you have concerns regarding the continuation  
23 of this pilot program?

24 A. Yes, we do not believe the continuation of the

1 differentiated gas pilot program, as outlined by  
2 the Companies, is in the best interest of  
3 ratepayers. Alternatively, Staff believes that  
4 a modified continuation of the differentiated  
5 gas pilot program is more appropriate.

6 Q. What alternative do you recommend?

7 A. Our proposal is to allow the Companies to  
8 continue the differentiated gas pilot program  
9 for the Rate Year at the previous annual cap of  
10 \$250,000. The differentiated gas pilot program  
11 was initiated as a knowledge gathering effort to  
12 better understand the utility procurement  
13 process for differentiated natural gas alongside  
14 potential benefits to portfolio diversification  
15 and emissions mitigation. The Companies'  
16 differentiated gas pilot program, as indicated  
17 in DPS-791, has only reported two years' worth  
18 of data over the three years of the program. We  
19 recommend an additional year of reporting to  
20 meet the knowledge gathering goals of the pilot  
21 program and achieve an appropriate dataset size  
22 to draw reasonable conclusions. Additionally,  
23 should customers want to purchase DNG after the  
24 pilot program ends in the Rate Year, they may do

1 so via their direct marketer, or ESCO.

2 Q. Do you have any additional recommendations?

3 A. Yes. The Panel recommends modifications to the  
4 reporting format requirements for the  
5 differentiated gas pilot program. We propose  
6 the Companies follow the requested formatting  
7 and reporting as indicated in Exhibit\_\_ (SGIOP-  
8 5).

9 Q. Do the Companies make any proposals regarding  
10 the sharing mechanisms in the Gas Cost Incentive  
11 Mechanism?

12 A. Yes. Beginning on page 49 of the EGSIP  
13 testimony, the Companies describe the current  
14 sharing of revenues through the Gas Cost  
15 Incentive Mechanism, or GCIM. Currently, the  
16 Companies share of revenues is 15 percent for  
17 the following: non-migration capacity release,  
18 off-system sales, and optimization transactions.  
19 The Companies' share of revenues is 20 percent  
20 for local production. The remaining revenues  
21 are returned to ratepayers. The Companies state  
22 that they have eliminated several long-haul  
23 contracts which has resulted in a reduction in  
24 commodity costs, reducing the revenues for the

1           aforementioned transactions. Therefore, the  
2           Companies propose to increase the Companies  
3           share for non-migration capacity release, off-  
4           system sales, and optimization transactions to  
5           twenty percent as an incentive to continue to  
6           maximize these revenues.

7   Q.    Do you agree?

8   A.    No. Fifteen percent provides adequate incentive  
9           for the Companies to maximize these revenues.  
10        We reject the idea that the Companies would need  
11        an additional five percent of the revenues to  
12        continue to maximize these revenues.

13   Q.    What do you recommend?

14   A.    We recommend the existing parameters of the  
15           sharing mechanisms in the GCIM remain.

16   Q.    Do you have any other recommendations?

17   A.    Not at this time. This concludes our testimony.

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