ATTACHMENT 2

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 24-E-0322

PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF NIAGARA MOHAWK POWER CORPORATION D/B/A NATIONAL GRID FOR ELECTRIC SERVICE

CASE 24-G-0323

PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF NIAGARA MOHAWK POWER CORPORATION D/B/A NATIONAL GRID FOR GAS SERVICE

JOINT PROPOSAL

By and Among:

Niagara Mohawk Power Corporation d/b/a National Grid
Department of Public Service Staff
Multiple Intervenors
Walmart, Inc.
New York Solar Energy Industries Association
Independent Power Producers of New York, Inc.
United States Department of Defense and all other Federal Executive Agencies
Turning Stone Enterprises, LLC
Fedrigoni Special Papers North America, Inc.
Alliance for a Green Economy
Empire Natural Gas Corporation
New York Geothermal Energy Organization
New Yorkers for Clean Power
International Brotherhood of Electrical Workers Local Union No. 97
New York Power Authority

Dated: April 25, 2025

Table of Contents

List of Appendices

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case 24-E-0322 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service

Case 24-G-0323 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service
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JOINT PROPOSAL

This Joint Proposal ("Joint Proposal") is made this 25th day of April 2025, by and among Niagara Mohawk Power Corporation d/b/a National Grid ("Niagara Mohawk" or "Company"), New York State Department of Public Service Staff ("Staff"), Multiple Intervenors, Walmart Inc., New York Solar Energy Industries Association ("NYSEIA"), Independent Power Producers of New York, Inc. ("IPPNY"), United States Department of Defense and all other Federal Executive Agencies, New Yorkers for Clean Power, Turning Stone Enterprises, LLC, Fedrigoni Special Papers North America, Inc. ("Fedrigoni Special Papers"), Empire Natural Gas Corporation,[1] Alliance for a Green Economy ("AGREE"), New York Geothermal Energy Organization ("NYGEO"), International Brotherhood of Electrical Workers Local Union No. 97 ("IBEW"),[2]

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1 Fedrigoni Special Papers and Empire Natural Gas Corporation only intervened in Case 24-G-0323; as such, support of this Joint Proposal is limited to that case, and they do not take a position with respect to any of the other provisions in the Joint Proposal related to Case 24-E-0322.

2 IPPNYand IBEW only intervened in Case 24-E-0322; as such, support of this Joint Proposal is limited to that case, and they do not take a position with respect to any of the other provisions in the Joint Proposal related to Case 24-G-0323.

and the New York Power Authority ("NYPA")[3] (collectively, the "Signatory Parties").[4] This Joint Proposal establishes a three-year rate plan for Niagara Mohawk's electric and gas businesses and either resolves or establishes a framework for resolving all issues raised in Cases 24-E-0322 and 24-G-0323 ("Rate Cases"), including provisions supportive and in furtherance of, the objectives of enhancing access to the Energy Affordability Program ("EAP") and advancing the goals of the Climate Leadership and Community Protection Act ("CLCPA").

I. <u>Background</u>

1. <u>Notable Aspects of the Joint Proposal</u>

The Joint Proposal provides funding for infrastructure upgrades that will enable the Company to safely and reliably meet customers' energy needs. The Joint Proposal also includes investments and programs to continue taking actions to advance the CLCPA goals, including more robust non-pipe alternatives ("NPAs"), an integrated energy pilot, programs to enhance distributed energy resources ("DER") interconnections, and commitments to support electrification options for current and prospective gas customers, reduce system leaks and associated methane emissions, and provide additional reporting on projects and programs impacting Disadvantaged Communities ("DACs").

The Signatory Parties have taken steps towards mitigating costs in the Joint Proposal. At the outset, the Company delayed its rate filing one month. As a result, the Joint Proposal reflects new rates for an 11-month period in Rate Year One instead of the customary 12 months.

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3 NYPA's support of this Joint Proposal is limited to Section IV 6.1.1, 6.8, and 6.9, and it does not take a position with respect to any of the other provisions in the Joint Proposal.

4 In addition, the New York State Office of General Services and the Environmental Defense Fund while not signing this Joint Proposal, have stated they will not oppose it.

Additional examples of ways the Joint Proposal mitigates costs include: removing discretionary spending and non-essential programs from the Company's original rate filings and deferring capital investments; reflecting more than $110 million in annual efficiency savings; utilizing rate mechanisms (*e.g.*, levelization) to smooth the impact of bill increases over several years; spreading the impact of compressed electric rates through the end of Rate Year Two; incorporating downward tracking mechanisms for investments in utility plant and information technology to ensure that customers will not be harmed if the Company underspends its capital programs; additional resources to support the Company's energy affordability programs ("EAP"); and enhanced customer protections for financially vulnerable customers.

2. Rate Case Filings

On May 28, 2024, Niagara Mohawk filed revised tariff leaves and supporting testimony and exhibits for new rates and charges for electric and gas service to be effective July 3, 2024.[5] The new tariffs were designed to increase electric and gas delivery revenues by approximately $525 million and $148 million, respectively, for the 12 months ending March 31, 2026.

Administrative law judges ("ALJs") were appointed to conduct the proceedings and to review Niagara Mohawk's rate filings. On June 25, 2024, the ALJs held a virtual procedural conference that was immediately followed by a technical presentation by the Company discussing various aspects of the rate filings.

[5] On June 7, 2024, the Secretary issued a Notice suspending the effective date of the Company's new rates until October 30, 2024. On September 10, 2024, the Secretary issued a Notice further suspending the effective date of the Company's new rates until April 30, 2025, unless otherwise ordered by the Commission.

On July 1, 2024, the ALJs issued a "Procedural Ruling" that provided dates for certain activities in the cases, including the filing of parties' initial and rebuttal testimony and hearings. The active parties engaged in extensive discovery throughout the proceedings, with the Company responding to more than 1,600 information requests.

Niagara Mohawk filed corrections and updates testimony and exhibits on July 22, 2024, decreasing the electric revenue requirement to approximately $509.6 million and increasing the gas revenue requirement to approximately $156.5 million. On September 26, 2024, 13 parties, including Staff, filed direct testimony and exhibits addressing the Company's filing. Niagara Mohawk, Staff, and five other parties each filed rebuttal testimony and exhibits on October 18, 2024.

a. <u>Public Statement Hearings</u>

On August 26, 2024, the Commission issued a "Notice Soliciting and Announcing Virtual Public Statement Hearings," inviting members of the public wishing to comment on any aspect of these proceedings to make statements on the record at a virtual public statement hearing held on September 25, 2024, or to submit written comments by February 28, 2025. Also, on August 26, 2024, the Commission issued a "Notice Soliciting Comments and Announcing In-Person Public Statement Hearings" that invited members of the public to participate in one of three in-person public statement hearings held on September 17, 2024 in Albany, New York, September 18, 2024 in Clay, New York and September 24, 2024 in Buffalo, New York. Transcripts for all of the public statement hearings were posted on the Commission's website.

b. <u>The Settlement Process</u>

On October 21, 2024, Niagara Mohawk notified the active parties of the commencement of settlement negotiations in these proceedings, pursuant to the Commission's settlement procedures set forth in 16 NYCRR § 3.9, and filed a formal notice of impending settlement negotiations with the Secretary.

Settlement negotiations were held on October 30, November 7, 8, 12, 14, and 21, December 2, 5, 9, 12, 13, and 19, 2024, January 7, 9, 10, 15-16, 23, and 30, February 6 and 13, and March 6, 13, 18, 20, 26, 27 and April 3, 7, 10, and 15, 2025. All settlement conferences were duly noticed to the active parties and held in either a hybrid in-person/virtual format, or virtually via video conference, which included the option to participate by telephone.

To facilitate settlement discussions and allow time to finalize this Joint Proposal, on October 29, 2024 and January 31, 2025, Niagara Mohawk filed requests to extend the suspension period (most recently through July 31, 2025), subject to a make whole provision that would restore the Company and customers to the same financial position they would have been in had there been no extension and new rates went into effect on May 1, 2025.

This Joint Proposal is the product of the active parties' settlement negotiations and was developed pursuant to, and in accordance with, the Commission's settlement procedures. The Signatory Parties believe that this Joint Proposal represents a fair and reasonable resolution of the issues presented in these proceedings and satisfies the requirements of Public Service Law § 65(1) that Niagara Mohawk provide safe and adequate service at just and reasonable rates.

II. **Overall Framework**

The Signatory Parties have developed a comprehensive set of terms and conditions for a three-year rate plan for Niagara Mohawk's electric and gas businesses. The terms and conditions of this rate plan are set forth below and in the attached Appendices. Specifically, this Joint Proposal addresses the following topics:

1. Effective Date and Term;
2. Electric and Gas Revenue Requirements;
3. Electric Revenue Allocation and Rate Design;
4. Gas Revenue Allocation and Rate Design;
5. Computation and Disposition of Excess Earnings;
6. Electric and Common Capital Investment Levels and Infrastructure and Operations Programs;
7. Gas Capital Investment Levels and Infrastructure and Operations Programs;
8. Advanced Metering Infrastructure ("AMI");
9. Information Technology ("IT");
10. Street Lighting;
11. Electric and Gas Reconciliations, Deferrals and True-Ups;
12. Electric and Gas Service Quality Assurance Programs and Other Performance Metrics;
13. Gas Safety Performance Metrics;
14. Customer Programs;
15. Earnings Adjustment Mechanisms;

16. Gas Matters;

17. CLCPA and Other Future of Heat Matters;

18. Filing for New Rates;

19. Corporate Structure and Affiliate Rules; and

20. Other Provisions.

The Joint Proposal contains provisions that recognize, address, and support the goals of the CLCPA. For example, Section IV of this Joint Proposal includes the following sections:

(i) Section 6.1 – Electric Capital Investment Levels

(ii) Section 6.6 – Non-Wires Alternatives (“NWAs”)

(iii) Section 6.8 – Self-Performance of Electric Distribution Upgrades Program

(iv) Section 6.9 – N-1 Assessment of Distributed Energy Resources Hosting Capacity

(v) Section 6.10 – Battery Storage

(vi) Section 7.1 – Gas Capital Investment Levels

(vii) Section 7.5.1 – Energy Transfer Station Site 2 Locations

(viii) Section 7.5.2 – Zero-Emission Gas Supply Transport Services Procurement

(ix) Section 13.1 – Leak-Prone Pipe (“LPP”) Removal

(x) Section 13.2 – Leak Management

(xi) Section 14.1 – Energy Affordability Program (“EAP”)

(xii) Section 14.1.1 – EAP Outreach in DACs

(xiii) Section 14.1.2 EAP Enrollment Targets

(xiv) Section 14.2 – Education and Outreach to Commercial and Industrial Customers

(xv) Section 14.3 – Extreme Weather Protections

(xvi) Section 14.4 – Special Protections

(xvii) Section 14.5 – Outreach and Education Plans

(xviii) Section 14.6 – Energy Efficiency Program Costs

(xix) Section 14.7 – Economic Development Program

(xx) Section 14.11 – Weatherization Health and Safety Program

(xxi) Section 16.1 – Non-Pipe Alternatives ("NPAs")

(xxii) Section 16.2 – NPA – Heat Pump Monthly Credit

(xxiii) Section 16.3 – Gas Marketing

III. Definitions

1. "Effective Date" means May 1, 2025, or such other date as the Commission may determine.

2. "Rate Year One" means April 1, 2025 through March 31, 2026.[6]

3. "Rate Year Two" means April 1, 2026 through March 31, 2027.

4. "Rate Year Three" means April 1, 2027 through March 31, 2028.

5. "2021 Joint Proposal" means the Joint Proposal, dated September 27, 2021, in Cases 20-E-0380, *et al.*, the terms of which were adopted by the Commission in those proceedings, pursuant to the Commission's "Order Adopting Terms of Joint Proposal, Establishing Rate Plans and Reporting Requirements" (issued January 20, 2022) ("2022 Rate Order").

[6] Because new rates are not effective until May 1, 2025, deferral and revenue targets in Rate Year One have been adjusted to align the targets with the start of new revenues. The relevant appendices include examples showing how targets will be calculated in Rate Year One.

6. "Fiscal Year" means the 12-month period ending March 31 of a given year. When a specific year is stated, it is the year in which the Fiscal Year ends (*e.g.*, Fiscal Year 2026 is the 12 months ending March 31, 2026).

7. The three Rate Years are collectively referred to herein as "Rate Years" and individually as a "Rate Year."

IV. Rate Plan

1. Effective Date and Term

The term of Niagara Mohawk's electric and gas rate plan is three years, beginning April 1, 2025 and continuing through March 31, 2028. For administrative reasons, certain targets and mechanisms are on different 12-month schedules (*e.g.*, calendar year periods), as set forth herein. In addition, unless specifically noted in this Joint Proposal, all terms of this Joint Proposal will continue in effect until changed by the Commission.

2. Electric and Gas Revenue Requirements

2.1. Rate Plan Revenue Requirements

This Joint Proposal provides for Rate Year One, Rate Year Two, and Rate Year Three electric and gas revenue requirement increases as follows:[7]

Electric		**Unlevelized***	**Levelized****
Rate Year One	Revenue Increase ($M)	$288.4	$167.3
	Impact on Delivery	10.9%	6.4%
	Impact on Total Bill	5.8%	3.4%
Rate Year Two	Revenue Increase ($M)	$141.7	$297.4
	Impact on Delivery	4.9%	10.9%
	Impact on Total Bill	2.7%	5.6%
Rate Year Three	Revenue Increase ($M)	$194.8	$243.4

[7] The percent increases in the table are based on total system revenues and include an estimated level of Energy Service Company ("ESCO") commodity revenues.

	Impact on Delivery	6.5%	8.2%
	Impact on Total Bill	3.7%	4.6%

* Unlevelized amounts include Gross Receipts Taxes ("GRT").
** Levelized amounts do not include GRT.

Gas		**Unlevelized***	**Levelized****
Rate Year One	Revenue Increase ($M)	$91.1	$57.4
	Impact on Delivery	16.9%	10.8%
	Impact on Total Bill	8.8%	5.5%
Rate Year Two	Revenue Increase ($M)	$31.1	$64.5
	Impact on Delivery	4.9%	10.8%
	Impact on Total Bill	2.6%	5.5%
Rate Year Three	Revenue Increase ($M)	$38.6	$71.8
	Impact on Delivery	5.7%	10.8%
	Impact on Total Bill	3.2%	6.0%

* Unlevelized amounts include GRT.
** Levelized amounts do not include GRT.

The components of the electric and gas revenue requirements are set forth in Appendix 1, Schedules 1 and 2. The revenue requirements are based on the following parameters:

a. a return on equity ("ROE") of 9.5 percent[8] for the term of the rate plan;

b. a capital structure and overall cost of capital consisting of the following components and rates:

8 One pre-tax basis point of ROE is equivalent to approximately: (i) $0.589 million and $0.147 million in electric and gas revenues, respectively, in Rate Year One; (ii) $0.647 million and $0.161 million in electric and gas revenues, respectively, in Rate Year Two; and (iii) $0.703 million and $0.173 million in electric and gas revenues, respectively, in Rate Year Three. These estimated basis point values will be used for purposes of calculating negative or positive revenue adjustments incurred during these periods and to determine if certain thresholds have been met. Until the Company's rates are next reset, basis point value used for calculating negative or positive revenue adjustments will remain at the Rate Year Three level.

Rate Year One

	% of Capital	Annual Cost	Weighted Cost Percent	Weighted Cost Pre-Tax
Long-Term Debt	51.39%	4.45%	2.29%	2.29%
Customer Deposits	0.36%	3.00%	0.01%	0.01%
Preferred Stock	0.25%	3.66%	0.01%	0.01%
Common Equity	48.00%	9.50%	4.56%	6.22%
Total Capital	**100.00%**		6.87%	8.54%

Rate Year Two

	% of Capital	Annual Cost	Weighted Cost Percent	Weighted Cost Pre-Tax
Long-Term Debt	51.45%	4.59%	2.36%	2.36%
Customer Deposits	0.32%	3.00%	0.01%	0.01%
Preferred Stock	0.23%	3.66%	0.01%	0.01%
Common Equity	48.00%	9.50%	4.56%	6.22%
Total Capital	**100.00%**		6.94%	8.61%

Rate Year Three

	% of Capital	Annual Cost	Weighted Cost Percent	Weighted Cost Pre-Tax
Long-Term Debt	51.55%	4.85%	2.50%	2.50%
Customer Deposits	0.26%	3.00%	0.01%	0.01%
Preferred Stock	0.19%	3.66%	0.01%	0.01%
Common Equity	48.00%	9.50%	4.56%	6.17%
Total Capital	**100.00%**		7.08%	8.70%

c. A Rate Year One electric rate base of $8.986 billion and a gas rate base of $2.242 billion, a Rate Year Two electric rate base of $9.876 billion and a gas rate base of $2.458 billion, and a Rate Year Three electric rate base of $10.821 billion and a gas rate base of $2.665 billion.

d. Niagara Mohawk's gas and electric depreciation rates have been updated and are set forth in Appendix 1, Schedule 3 for electric operations and Appendix 1, Schedule 4 for gas operations. These revised depreciation rates reflect (i) the continuation of the amortization of LPP for gas operations, (ii) the continued amortization of automated meter reading ("AMR") meters and encoder receiver transmitters ("ERTs") for electric and gas operations, and (iii) a 20-year amortization of depreciation reserve deficiencies of $124.137 million for electric operations and $20.287 million for gas operations.

2.1.1. Amortization of Excess Deferred Taxes

The Company's revenue requirements for its electric and gas operations reflect the amortization of excess accumulated deferred income taxes ("ADIT") related to unprotected plant over a four-year period, the continued amortization of ADIT related to protected plant using the average rate assumption method ("ARAM"), and the amortization of unprotected non-plant over 40 years.[9] If, during the term of this Joint Proposal, the Company determines that the amortization of excess ADIT related to protected plant would be in violation of the tax normalization provisions of the Internal Revenue Code such that the Company would be precluded from the full use of accelerated depreciation, then the Company shall have the right to modify its accounting for ADIT and the amortization of excess ADIT related to protected plant, as, and to the extent necessary to maintain consistency with applicable tax normalization principles and remain eligible to use accelerated depreciation without interruption. To the extent the Company determines that it is necessary to modify its accounting for ADIT and/or its amortization of excess ADIT related to protected plant to avoid a normalization violation, the Company shall file a notice of such action

[9] The unprotected amounts being amortized reflect both unprotected excess ADIT as well as the flow through effect of other historic plant-related timing differences such as depreciation and cost of removal. The unamortized balance of the flow through effect of cost of removal is being fully amortized over four years and cost of removal is subsequently treated as a normalized plant-related timing difference.

with the Secretary to the Commission. Such notice shall provide an explanation of the change in the tax normalization provision and/or the Internal Revenue Service's interpretation of the tax normalization provision of the Internal Revenue Code that results in a need for the Company to modify its accounting for ADIT and/or its amortization of excess ADIT related to protected plant. Further, the notice shall include the Company's proposed modification to avoid a tax normalization violation, the materiality of the proposed modification, and the Company's proposed rate treatment of the impact of the proposed modification. Any issues raised by the Company's notice shall be resolved in its next base rate case proceeding.

2.1.2. Amortization of Net Electric Regulatory Asset Balances

The Company's revenue requirements for electric operations reflect the amortization of its net electric regulatory asset balance as of December 31, 2023 of $186.7 million over ten years as set forth in Appendix 5, Schedule 1.

2.1.3. Amortization of Rate Case Expenses

The Company's electric and gas revenue requirements reflect the amortization of $2.82 million of rate case expenses over the three-year term of the rate plans. If the Company does not file for new rates to be effective April 1, 2028, it will create a regulatory liability for amortized rate case expense collected during periods after March 31, 2028.

2.2. Levelization of Rate Increases

In recognition of the financial impacts of the proposed rates on the Company's customers, the Signatory Parties propose that the base rate changes be implemented on a levelized percentage basis over the term of the rate plan. Additionally, to further mitigate electric bill impacts because of rate compression in Rate Year One, the Signatory Parties propose to spread the impact of $46.5

million of compressed electric rates from Rate Year One to Rate Year Two. The annual revenue changes, with and without levelization, are set forth in Appendix 1, Schedule 6 for the Company's electric and gas operations.

2.2.1 Construction Work in Progress ("CWIP") Treatment for CLCPA Phase 2 Transmission Projects

The Signatory Parties acknowledge that spreading the impact of compressed electric rates through the end of Rate Year Two smooths electric customer bill impacts but delays the Company's cash recoveries until later in the rate plan. Therefore, the Signatory Parties agree that the Company may petition the Commission under Case 20-E-0197 to request authorization to petition the Federal Energy Regulatory Commission ("FERC") to include in rate base 100 percent of CWIP associated with the CLCPA Phase 2 Projects. The Signatory Parties retain their right to take any position they deem appropriate in response to such petition.

2.3. Make Whole Provision

The Signatory Parties recognize that Commission approval of this Joint Proposal may occur after May 1, 2025. Accordingly, the Signatory Parties propose that the Company will recover the revenue shortfall resulting from the extension of the suspension period from and after May 1, 2025 through a make whole provision. The make whole provision is designed to ensure the Company is restored to the same position it would have been in had new rates gone into effect on May 1, 2025.

To implement the make whole, the Company will implement compressed delivery rates and make the appropriate revenue adjustments through the Company's revenue decoupling mechanisms for both electric and gas operations. All other revenue (excluding non-decoupled revenue and all non-reconciled miscellaneous revenue) will be reconciled through updated Rate

Year targets established in this Joint Proposal for existing reconciliation mechanisms, including the Revenue Decoupling Mechanism ("RDM"), Net Revenue Sharing, Transmission Revenue Adjustment Clause ("TRAC"), and the reconcilable components of the Merchant Function Charge ("MFC"). Additionally, the Company will make revenue adjustments for the unreconcilable components of the MFC, which includes uncollectible expense and working capital. Revenue adjustments will include applicable carrying charges. An illustrative calculation of the MFC make whole provision is included in Appendix 2, Schedule 15 for electric and Appendix 3, Schedule 15 for gas. Financial true-up targets established in this Joint Proposal, as well as depreciation and amortization expense, will be applied to the extension of the suspension period. All accounting/ratemaking will be in accordance with this Joint Proposal and be effective as of May 1, 2025.

To moderate the impact of electric rate compression, the Joint Proposal proposes recovery of the Rate Year One base delivery net electric increases over the extended period of September 1, 2025 to March 31, 2027. The Rate Year One gas delivery net increases, however, will be recovered over the compressed period of September 1, 2025 to March 31, 2026. If new rates do not become effective on September 1, 2025, the Company will recalculate the compressed rates to reflect the commensurate recovery period.

3. <u>Electric Revenue Allocation and Rate Design</u>

3.1. Electric Revenue Forecast

The retail delivery electric revenue sales forecast at current rates is set forth in Appendix 2, Schedule 1. Appendix 2, Schedules 1.1 - 1.3 depict the Rate Year One through Rate Year Three revenue using the sales forecast at current delivery rates. The revenue forecasts will also include the forecast miscellaneous revenues for each rate year.

3.1.1. TCC Auction Revenues

The electric revenue forecast used to develop the Company's revenue requirement reflects TCC Auction Revenues of $374.5 million in Rate Years One, Two, and Three. Pursuant to its P.S.C. No. 220 – Electric Service Tariff ("Electric Service Tariff"), the Company will continue to defer the differences between its actual TCC Auction Revenues and the level identified in rates, exclusive of revenue taxes, and recover such differences through the TRA surcharge. This deferral mechanism is discussed more fully in Section IV.11.1.16. Consistent with the 2021 Joint Proposal, the Company will continue to be permitted to retain the return on equity established by the FERC for the Energy Highway, Western New York, and Smart Path Connect projects.[10]

3.2. Electric Revenue Allocation

No embedded cost of service ("ECOS") methodology or set of assumptions sponsored by any party in these proceedings for allocating the overall revenue requirements will establish precedent for revenue allocation in any future proceeding. The revenue allocation recommended in this Joint Proposal does not endorse any one ECOS methodology or set of assumptions and will not establish precedent for any future proceeding. The results of the ECOS study and the development of the allocation are provided in Appendix 2, Schedule 2.

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[10] *See* FERC Docket Nos. 6 ER23-973-001, ER23-974-001, "Order on Tariff Filings, and Establishing Hearing and Settlement Judge Proceedings," issued July 28, 2023 (authorizing cost recovery for the Smart Path Connect project, including use of the FERC-approved ROE); Case 20-E-0380, "Order Adopting Terms of Joint Proposal, Establishing Rate Plans and Reporting Requirements," Joint Proposal at Section IV.3.1.1 (permitting the Company to retain the FERC ROE for any New York Power Authority Priority Transmission projects, any Western New York Transmission projects, and any similar FERC-regulated transmission projects).

Revenue allocation is shown in Appendix 2, Schedule 3A. Rate Year One, Rate Year Two, Rate Year Three, and post-Rate Year Three revenue increases will be allocated to service classes as shown on Appendix 2, Schedules 3B-3F. A summary of all rates is shown on Appendix 2, Schedule 3K.

3.3. Electric Rate Design

Niagara Mohawk's electric rates will be revised as shown in Appendix 2, Schedule 3K for standard service classes and Schedule 3H for Service Classification ("SC") -1 Voluntary Time-of-Use rates. SC-7 Standby Rates will be shown on Appendix 2, Schedule 5. The Company will also update the delivery and supply incentive rates for the Residential Electric Vehicle Charge Smart Plan, as shown on Appendix 2, Schedule 6.

The Company's rate design includes incremental EAP costs associated with the proposed revenue requirement increases. Typical bill impacts for standard service classes resulting from this rate design are set forth in Appendix 2, Schedule 4. The EAP customer discounts shown in the bill impact tables are presented for illustrative purposes. The actual EAP customer discounts are calculated annually and filed each year on or about November 1 in Case 14-M-0565. In addition, the Company will file revised EAP bill discounts for Rate Year One concurrent with any tariff compliance from the Commission's rate order in these proceedings.

3.3.1. Excelsior Job Program Rates

The Excelsior Job Program ("EJP") rates will be revised as shown in Appendix 2, Schedule 10.

3.4. Modifications to Tariff, Fees and Provisions – Electric

Unless otherwise specified, the tariff modifications set forth in this section will be made in the first tariff compliance filing directed by a Commission order adopting the terms of this Joint Proposal.

3.4.1. Earnings Adjustment Mechanism Surcharge

The Company will continue to recover earned electric Earnings Adjustment Mechanism ("EAM") positive revenue adjustments through the existing EAM surcharge. EAM revenues will be allocated as follows:

1. Electric EAMs:

(i) Storage Megawatt ("MW") EAM revenue will be allocated to customer classes using the 1 Coincident Peak ("1CP") allocator;

(ii) Electric Demand Response EAM revenue will be allocated to customer classes using the 1 CP allocator;

(iii) Transportation Electrification EAM revenue will be allocated to customer classes using the Total Distribution Revenue ("Tot_DistRev") allocator; and

(iv) Electric Vehicle ("EV") Managed Charging Residential EAM revenue will be allocated to customer classes using the Non-Coincident Peak ("NCP_Pri") allocator.

(v) L2 and DCFC Make-Ready Share the Savings EAM will be allocated to customers using the Tot_DistRev allocator.

Earned EAM revenue will be recovered from non-demand metered classes on a per kWh basis and for demand metered classes on a per kW basis. An illustrative example of the EAM calculation is provided in Appendix 2, Schedule 14.

2. Gas EAMs:

(i) Gas Demand Response EAM revenue will be allocated to customer classes using the Peak Sendout ("Peak_Sendout") allocator. An illustrative example of the EAM calculation is provided in Appendix 3, Schedule 11.

3.4.2. Demand Response Program Charges

The Company's customer charges for customers that participate in (i) the Emergency Demand Response Program, (ii) the Day Ahead Demand Response Program, (iii) the Commercial System Relief Program, (iv) the Distribution Load Relief Program, and (v) the Term and Auto-Term DLM Program will be revised from $11.77 to $14.56 as shown in Appendix 2, Schedule 11.4.1.

3.4.3. Incremental Charges for SC-1, Special Provision L and SC-2, Special Provision O

The Company will revise the incremental monthly charge assessed to SC-1, Special Provision L and SC-2, Special Provision O customers from $3.11 to $4.42 as shown in Appendix 2, Schedule 11.4.2.

3.4.4. Incremental Charges for SC-2, Special Provision P and SC-3, Special Provisions L and N

The Company will revise the incremental monthly charges assessed to SC-2, Special Provision P and SC-3, Special Provisions L and N customers from $24.71 to $25.10 as shown in Appendix 2, Schedule 11.4.3.

3.4.5. Incremental Energy Efficiency Surcharge

As discussed further in Section IV.14.6, the Company will amend its tariff to modify its Incremental Energy Efficiency ("IEE") Surcharge to effectuate the recovery in rates of any difference between the energy efficiency costs reflected in rates and the costs authorized by the Commission in the Energy Efficiency Proceeding, as well as the recovery of any incremental energy efficiency costs that may be approved by the Commission in the future.[11]

The Signatory Parties acknowledge that future Commission action associated with the statewide Energy Efficiency/Building Electrification ("EE/BE") proceeding(s) may modify the way in which EE/BE costs are recovered.

3.4.6. Other Delivery Surcharge

The Company will amend its tariff to include an Other Delivery Surcharge ("ODS") to enable the Company to recover the delivery surcharges that are currently included in customer's billed delivery charge line, including Dynamic Load Management, Value of Distributed Energy Resource Value Standard, EAM Surcharge, EV Make-Ready, Arrears Management Program Phases 1 and 2 Surcharges, and the new Revenue Adjustment Mechanism ("RAM") surcharge as shown in section 3.12, through a single line item on customer bills. The ODS will also include any future approved delivery surcharges that are not included on a separate line item on customer bills. The Company will develop a plan to communicate information about the surcharge to customers that will include bill messages to communicate what is included in the ODS versus the Delivery Charge, updates to the Company's website to include a clear explanation of the ODS,

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[11] Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative ("Energy Efficiency Proceeding").

and updates to customer bills to incorporate the definition of the ODS line item. This plan and associated outreach materials will be provided to Staff and interested parties for review and feedback at least 30 days prior to implementation of the ODS. An illustrative example of the statement is shown in Appendix 2, Schedule 12.

3.4.7. Elimination of Late Payment Charge and Other Waived Fees ("LPCO"), Net Utility Plant ("NUP") and Hydrogen Energy Transfer System ("ETS") Surcharge

The Company will amend its tariff to terminate the LPCO, NUP, and Hydrogen ETS surcharges due to the expiration of those surcharges.

3.4.8. Empire Zone Rider

The Company will modify its tariff to eliminate the Empire Zone Rider program.

3.4.9. Standardized Interconnection Requirements

The Company will modify the Standardized Interconnection Requirements of its Electric Service Tariff to correct the title and reference to the "New York State Standardization Interconnection Requirements and Application Process for New Distributed Generation and/or Energy Storage System 5 MW or Less Converted In Parallel with Utility Distribution Systems" and otherwise conform to the requirements of the SIR Orders.[12]

[12] Case 15-E-0557, In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Distributed Generators 2 MW or Less, Order Modifying Standardized Interconnection Requirements (issued March 18, 2016); Case 18-E-0018, In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Small Distributed Generators, "Order Granting Clarification" (issued July 13, 2018) (collectively, the "SIR Orders").

3.4.10. SC-7 – On-Site Generation Definition

The Company will modify its Electric Service Tariff to revise the on-site generation definition in SC-7 to include energy storage systems in the definition of "on-site generation" under energy exported to the Company's distribution system is sold to the wholesale market.

3.4.11. Clean Energy Standard Delivery Charge

The Company will modify its tariff to reflect modified Clean Energy Standard Delivery ("CESD") provisions to include language to permit recovery of uncollectible costs through the CESD Charge.

3.4.12. Acceptable Forms of Payment

The Company will modify its tariff to include a list of acceptable forms of payment.

3.4.13. Non-Residential Customer Application

The Company will modify its non-residential service applications for service to permit customers to provide information concerning the account holder, the process to apply for a sales tax exemption, the customer's responsibility to inform the Company of material changes to the customer's use of equipment, and other housekeeping items.

3.4.14. Residential Rate Eligibility for Religious Organizations

The Company will modify its tariffs to clarify the eligibility of religious organizations for residential rates consistent with Section 76 of the Public Service Law.

3.4.15. Tariff Revisions Related to the Definition of the Rate Year Under This Joint Proposal

The Company will modify its tariffs where necessary to revise the definition of the term "Rate Year" consistent with this Joint Proposal.

3.4.16. Residential Automatic Meter Reading Opt-Out Fees

The Company will modify Rule 25.6 of its Electric Service Tariff to update its automatic meter reading ("AMR") Opt-Out fees. The initial fee, and re-installation fee, for removal of existing AMR meter and installation of non-AMR meter will be updated to $72.44 for an electric-only meter and to $134.53 for an electric and gas meter replacement. The monthly meter reading fee for an electric-only meter will be updated to $15.45 and the fee for a combination gas and electric meter reading will be $21.24. The updated fees are further provided in Appendix 2, Schedule 11.5. The same fees apply to customers who opt out of receiving an AMI meter.

3.4.17. Exemption from Reconnection Fees

The Company will continue to provide an exemption from reconnection fees for EAP recipients.

3.5. Paperless Billing Credit

The Paperless Billing Credit will be updated to $0.60 as shown in Appendix 2, Schedule 11.2.

3.6. Updated Billing Charges and Billing Back-out Credit

During the term of the rate plan, the Company's billing charges to an ESCO that supplies electricity to an electric only customer will be $0.92 per bill. The billing charge to an ESCO that supplies electric to a dual gas and electric customer will be $0.46 per bill. The backout billing credit to a dual gas and electric customer that is supplied electric by an ESCO and receives a consolidated bill from either the Company or the ESCO will be $0.46 per bill. The backout billing credit to an electric only customer that is supplied by an ESCO and receives a consolidated bill from the Company or an ESCO will be $0.92 per bill. The Company will modify Rule 39.11 of the tariff to update the applicable Billing Charges and Billing Back-out Credits as further specified in Appendix 2, Schedule 11.3.

3.7. Re-Establishment Charges and Disconnection Fees

Rule 9 of its Electric Service Tariff will be modified to update the applicable electric re-establishment fees for seasonal and non-seasonal customers, as provided in Appendix 2, Schedule 11.1.

3.8. Revenue Decoupling Mechanism

The RDM targets will be updated consistent with the final revenue requirement and rate design. The RDM in the Company's Electric Service Tariff will also be clarified to reflect that (i) unreconciled RDM balances prior to the reconciliation period may be recovered in the annual RDM reconciliation, (ii) if a new rate plan begins prior to the end of the RDM reconciliation period of the previous rate plan year a new RDM adjustment would be established for the 12-month period of the new rate plan period based on the RDM reconciliation balance at such time as the new RDM adjustment being set, and (iii) interim RDM adjustments may be set using a portion of the current reconciliation balance in order to manage customer bill impacts. The RDM targets for each service class for each year of the rate plan are as shown in Appendix 2, Schedule 9.

3.9. Merchant Function Charge

The MFC will be modified to reflect updated revenue targets, pre-tax weighted average cost of capital ("WACC"), and uncollectible percentages consistent with this Joint Proposal as shown in Appendix 2, Schedule 7. The MFC will also be clarified to state that the uncollectible percentage factors include capacity charges in the supply costs used in its calculations and the working capital on purchased power rates include capacity charges in the supply costs used in its calculation.

3.10. Next Base Rate Case

In its next base rate filing, Niagara Mohawk will submit as part of its response to the pre-filing information requests to the active parties in that proceeding: (i) a normalized historic embedded cost of service ("ECOS") that will include normalized expense by removing non-recurring items, using end-of-the-year plant balances, end-of-the-year customer costs and weather normalized billing events, and (ii) an electric *pro forma* ECOS based on proposed rates, revenue allocations and revenue requirements. Niagara Mohawk will not be required to use the results of the studies for any purpose. In addition, the Company will include a study of the load carrying capacity of the minimum system with the direct testimony of the Rate Design Panel that examines the applicability of load carrying capacity adjustments for the service classes.

3.11. Loss Factors

The electric loss factors will be updated as follows:

Voltage Delivery Load	Loss Factor
Transmission	1.032
Sub-Transmission	1.062
Primary	1.077
Secondary	1.103

3.12. The Rate Adjustment Mechanism – (Electric and Gas Tariffs)

The Company will implement a RAM in its electric and gas tariffs that will consolidate certain deferral balances into a single surcharge/credit for recovery from, or refund, to customers. The RAM will include the following deferrals:

(i) Property Taxes (Section IV.11.1.6); and

(ii) Major Storm Deferred Expenses (Section IV.11.1.12) (applicable to electric operations only).

Any costs recovered or pending recovery through the RAM will be subject to Staff audit. If Staff determines that an adjustment to a deferral account is needed following an audit, the Company will make such an adjustment to the related deferral account.

A RAM surcharge or credit will only be implemented to the extent that the deferred amount exceeds the value of ten basis points in the applicable Rate Year. The RAM surcharge is subject to an annual cap of 2.00 percent of the Company's actual operating revenues for the prior calendar year and will be recovered from July 1 through June 30 of the respective Rate Year. Amounts subject to recovery through the RAM in any Rate Year will be limited to the annual cap of 2.00 percent (*i.e.*, no compounding).

The first year of the RAM surcharge will commence on July 1, 2025 and will include deferral balances for Property Taxes and Major Storm Deferred Expenditures incurred during the period January 1, 2024 through March 31, 2025. Subsequent years will include cost deferrals during the previous Rate Year. An illustrative calculation of the RAM surcharge for Rate Year One through Three is presented on Appendix 2, Schedule 13 for electric and Appendix 3, Schedule 12 for gas. Appendix 3, Schedule 12.1 sets forth the processes and procedures for the RAM.

The Company will include an attachment showing the calculation of the RAM surcharge by service class and the applicable deferral balances to be recovered from/refunded to customers with its statement filing 30 days before a RAM surcharge effective date.

If the Commission does not issue any order adopting the Joint Proposal with an effective date prior to June 1, 2025, the Company will file its first RAM statement to be effective on the first of the month following the issuance of an order adopting the Joint Proposal in these proceedings. The RAM collection period will be compressed and recovered/refunded to customers through June 30, 2026.

4. Gas Revenue Allocation and Rate Design

4.1. Gas Revenue Forecast

The revenue forecast at current rates for each Rate Year is set forth in Appendix 3, Schedule 1. The delivery rate revenue forecasts used to develop base rates and the reconciliation to total gas Operating Revenues for the Rate Years are set forth in Appendix 3, Schedule 3.

4.2. Gas Revenue Allocation

No ECOS methodology or set of assumptions sponsored by any party in these proceedings for allocating the overall revenue requirements will establish precedent for revenue allocation in any future proceeding. The revenue allocation recommended in this Joint Proposal does not endorse any one ECOS methodology or set of assumptions and will not establish precedent for any future proceeding. Revenues and expenses allocated to SC-6 will be shown in the ECOS for illustrative purposes only and not used for revenue allocation or rate design purposes.

Gas revenue allocation is shown in Appendix 3, Schedule 3A. Rate Year One, Rate Year Two, Rate Year Three, and post-Rate Year Three revenue increases will be allocated to service classes as shown on Appendix 3, Schedule 3B through 3F. A summary of all rates is shown on Appendix 3, Schedule 3I.

4.3. Gas Rate Design

Niagara Mohawk's gas rates will be revised as shown in Appendix 3, Schedule 3I. Bill impacts resulting from this rate design are set forth in Appendix 3, Schedules 4.1 – 4.4. The

Company's gas rate design includes incremental EAP costs associated with the revenue requirements. SC-6 will have volumetric delivery rates set at a 45-percent discount to the applicable firm tail block rate of SC-8. The EAP customer discounts shown in the bill impact tables are presented for illustrative purposes. The actual EAP customer discounts are calculated annually and filed each year on or about November 1 in Case 14-M-0565. In addition, the Company will file revised EAP bill discounts for Rate Year One concurrent with any tariff compliance from the Commission order adopting the terms of this Joint Proposal.

4.4. Gas Tariff Modifications

Unless otherwise specified, the P.S.C. No. 219 – Gas Service Tariff ("Gas Service Tariff") modifications set forth in this section will be made in the first tariff compliance filing directed by a Commission order adopting the terms of this Joint Proposal.

4.4.1. Elimination of LPCO and NUP Surcharges

The Company will eliminate the LPCO and NUP Surcharges from its Gas Service Tariff due to the expiration date of those surcharges.

4.4.2. Earnings Adjustment Mechanism Surcharge

The Company will continue to recover earned gas EAM positive revenue adjustments through the existing EAM surcharge. EAM revenue will be allocated to firm sales and transportation customers, exclusive of EJP load, in the manner set forth in Section IV.3.4.1 of this Joint Proposal.

4.4.3. Excelsior Jobs Program

The Company will adopt new marginal EJP cost rates, as shown in Appendix 3, Schedule 9. The EJP rates include an energy efficiency adder to reflect the fact that EJP customers are eligible for the Company's energy efficiency programs. The Company will phase in the gas EJP rates over a five-year period, as shown in Appendix 3, Schedule 9.1. The Company will perform an annual review of all EJP customer classes that may pay more in EJP marginal rates than under the otherwise applicable standard tariff rate. If that review indicates a customer paid more on EJP rates than on the standard tariff rate, the Company will provide a refund of the difference.

4.4.4. Exemption from Reconnection Fees

The Company will continue to provide an exemption from reconnection fees for EAP recipients.

4.4.5. Residential Automatic Meter Reading Opt-Out Fees

The Company will modify Rule 13.6 of its Gas Service Tariff to update AMR Opt-Out fees. The initial fee and re-installation fee, for removal of existing AMR meter and installation of non-AMR meter will be updated to $103.49 for a gas only meter and to $134.53 for an electric and gas meter replacement. The monthly meter reading fee for a gas-only meter will be updated to $15.45, and the fee for a gas and electric meter reading will be $21.24. The updated fees are set forth in Appendix 3, Schedule 10.3. The same fees will apply to customers who opt out of receiving an AMI-enabled metering device.

4.4.6. Definition of Delivery Service Revenue In The RDM

The Company will modify Rule 32 of its Gas Service Tariff to simplify the definition of Delivery Service Revenue in the RDM such that the actual delivery service revenues subject to the RDM reconciliation mechanisms are customer charges (excluding low-income discounts) and base delivery rates (excluding economic development discounts) adjusted for the weather normalization adjustment.

4.4.7. SC-14 Tariff Modifications

The Company will modify SC-14 of its Gas Service Tariff as follows:

(i) to include additional means of communication to customers through electronic mail; and

(ii) to set forth the responsibility of customers to cover all costs related to decommissioning of any gas-powered electric generation facilities and/or transmission lines connected to such facilities upon their retirement.

4.4.8. Housekeeping Changes

The Company will modify its Gas Service Tariff for housekeeping changes to:

(i) include a reference to the Arrears Management Program surcharge mechanism in the list of EJP exemptions; and

(ii) correct minor grammatical errors throughout the tariff.

4.4.9. Net Revenue Sharing Target

The Company will update its Net Revenue Sharing ("NRS") targets for SC-6, SC-9, and SC-14 and revise tariff filing requirements as follows:

(i) the NRS targets will be updated to reflect the Rate Year revenues as set forth on Appendix 3, Schedule 8;

(ii) the requirement to file the calculation of the NRS amount 15 days prior to the effective date of the rate will be eliminated; and

(iii) the Company will file the calculation of the rate with its statement filing three days prior to the effective date.

4.4.10. SC-6 Annual Usage Threshold

The Company will modify SC-6 of the Gas Service Tariff to reduce the annual usage threshold from 2.5 million therms to 250,000 therms. The alternative fuel requirements for SC-6 will remain unchanged.

4.4.11. Empire Zone Rider

The Company will modify its Gas Service Tariff to eliminate the Empire Zone Rider program.

4.4.12. Incremental Energy Efficiency Surcharge

The Company will modify Rule 44 of its Gas Service Tariff – the IEE Surcharge – to permit the Company to recover any additional Commission-authorized budgets in the Energy Efficiency Proceeding that are greater than the rate allowance for each Rate Year and any future Commission approved incremental energy efficiency costs.

4.4.13. Revenue Tax Surcharge

The Company will modify its Revenue Tax Surcharge to modify the filing date for the statement from 15 business days to 15 days.

4.4.14. Acceptable Forms of Payment

The Company will modify its Gas Service Tariff to list acceptable forms of payment and to direct customers to the Company's website for a full list of accepted forms of payment.

4.4.15. Non-Residential Customer Application For Service

The Company will modify its Gas Service Tariff to provide the Company and the customer additional, relevant information in the gas service application process.

4.4.16. Eligibility of Religious Organizations For SC-1 Service

The Company will modify its Gas Service Tariff to clarify the eligibility of religious organizations for SC-1 Service consistent with Section 76 of the Public Service Law.

4.4.17. Rate Adjustment Mechanism

The Company will include the RAM in its tariff for gas service as more fully described in Section IV.3.12 of this Joint Proposal.

4.4.18. Pipeline Replacement Projects ("PRP") Surcharge Mechanism

The Company will include the PRP surcharge mechanism in its tariff for gas service as more fully described in Section IV.7.2. and IV.7.3. of this Joint Proposal.

4.4.19. Elimination of the Gas Safety and Reliability Surcharge ("GSRS")

The Company will eliminate the GSRS from the Gas Service Tariff effective November 1, 2026. The final collection period will be November 1, 2025 through October 31, 2026 and the surcharge will recover costs related to the stayout period July 1, 2024 through March 31, 2025. The Company will continue to accrue carrying charges on any remaining deferral balance as of October 31, 2026 at the pre-tax WACC.

4.5. Lost and Unaccounted for Gas

The LAUF targets and deadbands that will apply during the term of the rate plan are as follows:

Targets	%
LAUF Target	1.925%
Upper Band	2.925%
Lower Band	0.925%

The new LAUF targets and dead bands will become effective at the beginning of the new Gas Adjustment Clause ("GAC") year on September 1, 2025. The LAUF targets and deadbands included in the table above will be reconciled on a GAC year basis with the GAC year ending August 31st. The LAUF factor of adjustment calculation will be used to gross up gas costs for LAUF Gas. The loss percentage will be calculated by dividing losses by system receipts including any necessary adjustments. The Factor of Adjustment ("FOA") will be calculated as follows: FOA = 1/(1-loss percentage). The development of the LAUF targets and deadbands and the FOA are set forth in Appendix 3, Schedule 5.

4.6. Revenue Decoupling Mechanism

The RDM targets for each Rate Year are shown on Appendix 3, Schedule 7. The Company will modify Rule 32 in its Gas Service Tariff to clarify the definition of actual delivery service revenues subject to reconciliation through the RDM to be customer charges (excluding low-income discounts) and base delivery rates (excluding development discounts) adjusted for the weather normalization adjustment.

4.7. Merchant Function Charge

The MFC will continue with the modifications set forth in Appendix 3, Schedule 6.

4.8. Partially Interruptible Service Class

The Company will create a new pilot program service class that features partial interruptions, meaning that customers will be required to have primary point capacity ("PPC") on upstream pipeline system up to a certain threshold in order to receive firm transportation service on the Company's distribution system up to that threshold. Service provided beyond the threshold would be fully interruptible and the customer would not be required to maintain PPC for interruptible deliveries.

Within three months of an order approving this Joint Proposal the Company will host, at a minimum, one stakeholder meeting to obtain input for the pilot program. Within six months of an order approving this Joint Proposal, the Company will file a proposal in this proceeding for the pilot program to all interested parties that would include eligibility criteria, operational parameters, a proposed rate structure, and a proposed effective date for the pilot program. Interested parties will have the opportunity to provide comments, after which, within two months of the submission of the Company's proposal, the Company will file a petition in this proceeding requesting approval to implement the pilot program.

Customers switching to the partially interruptible class would be advised that a return to fully firm services would only be permitted if (i) the Company is able to confirm that its distribution system is capable of providing the reinstated level of firm service, and (ii) the customer is able to acquire PPC equivalent to a level it had prior to the switch to partially interruptible service.

4.9. Next Base Rate Case

In its next base rate filing as part of its response to the pre-filing information requests to the active parties in that proceeding, Niagara Mohawk will submit (i) a normalized historical ECOS that will include normalized expense by removing non-recurring items and will also include end-of-the-year plant balances and customer counts and weather normalization billing units; and (ii) a *pro forma* ECOS based on proposed rates, revenue allocation and revenue requirements. Niagara Mohawk will not be required to use the results of their studies for any purpose.

4.10. Paperless Billing Credit

The Paperless Billing Credit will be updated to $0.60 as shown in Appendix 3, Schedule 10.2.

4.11. Billing Charge/Billing Back-out Credit

During the term of the rate plan, the Company's billing charges to an ESCO that supplies gas to a gas only customer will be $0.92 per bill. The billing charge to an ESCO that supplies gas to a dual gas and electric customer will be $0.46 per bill. The backout billing credit to a dual gas and electric customer that is supplied gas by an ESCO and receives a consolidated bill from either the Company or the ESCO will be $0.46 per bill. The backout billing credit to a gas only customer that is supplied by an ESCO and receives a consolidated bill from the Company or an ESCO will be $0.92 per bill. The Company will modify the tariff to update the applicable Billing Charges and Billing Back-out Credits as further specified in Appendix 3, Schedule 10.1.

4.12. Re-establishment Charge

During the term of the rate plan, the gas re-establishment meter fee will be $80.00 during normal business hours and $96.00 after normal business hours as further specified in Appendix 3, Schedule 10.4.

5. <u>Computation and Disposition of Excess Earnings</u>

5.1. Earnings Report

By August 31 of each year, the Company will file an earnings report that will include audited financial statements using the methodology described in this Section and shown in Appendix 4. The earnings report will be used for the Earnings Sharing Mechanism set forth in Section IV.5.3.

The earnings report will calculate Niagara Mohawk's ROE for the preceding Rate Year using a capital structure with an equity component equal to 48 percent. Earnings are measured on an actual 12-month basis. In calculating earnings for Rate Year One, any incremental revenues, due to the change in base rates, for April 2025 resulting from the approval of this Joint Proposal will be excluded. In the event Niagara Mohawk does not file for new rates to be effective until after March 31, 2028, the earnings sharing threshold of greater than 10.0 percent for any period of time less than a year before new rates take effect will be prorated to develop a stub period earnings sharing threshold. The stub period will be calculated by adjusting the actual average rate base for that period by an operating income ratio factor. The operating income ratio factor will be calculated as the ratio of operating income during the same partial period in the previous Rate Year to the total operating income for that Rate Year. An example of the calculation for the stub period is shown in Appendix 4, Schedule 1.

5.2. Discrete Incentives and Revenue Adjustments

Niagara Mohawk will calculate its ROE based upon the Company's balance sheet and income statement (using only above-the-line revenues and costs) and by excluding the effects of the following discrete incentives and negative and positive revenue adjustments:

- Amounts previously booked in excess of earnings thresholds;
- Supplemental executive retirement plan costs;
- Electric and gas property tax sharing;
- Electric and gas customer service performance indicator revenue adjustments;
- Gas safety performance revenue adjustments;
- Electric and gas EAMs;

- Gas LAUF incentive amounts;
- Electric reliability revenue adjustments, which include the electric cost estimating and inspection and maintenance metrics;
- Gas revenue sharing for capacity release and off-system sales;
- Gas revenue sharing for SC-6; and
- NWA and NPA revenue adjustments.

The Company will also exclude any new incentives or positive revenue adjustments, if any are implemented by the Commission separate from the order setting rates in these proceedings.

5.3. Earnings Sharing Mechanism

If Niagara Mohawk's actual ROE in any Rate Year, excluding the discrete incentives and negative and positive revenue adjustments identified in Section 5.2, exceeds 10.0 percent, the amount in excess of 10.0 percent will be deemed "shared earnings" for the purposes of this Joint Proposal and be treated as follows:

5.3.1. ROE > 10.0% and ≤ 10.50%

If the level of earned ROE for Niagara Mohawk exceeds 10.0 percent but is less than or equal to 10.50 percent, 50 percent of the revenue equivalent of earnings in excess of 10.0 percent will be deferred for the benefit of customers and 50 percent will be retained by Niagara Mohawk.

5.3.2. ROE > 10.50% and ≤ 11.0%

If the level of earned ROE for Niagara Mohawk exceeds 10.50 percent but is less than or equal to 11.0 percent, 75 percent of the revenue equivalent of earnings in excess of 10.50 percent will be deferred for the benefit of customers and 25 percent will be retained by Niagara Mohawk. The Company will use 50 percent of its retained earnings under this Section IV.5.3.2, if any, to reduce regulatory asset balances associated with Site Investigation and Remediation ("SIR") activities.

5.3.3. ROE > 11.0%

If the level of earned ROE for Niagara Mohawk exceeds 11 percent, 90 percent of the revenue equivalent of earnings in excess of 11.0 percent will be deferred for the benefit of customers and 10 percent will be retained by Niagara Mohawk. The Company will use 50 percent of its retained earnings under this Section IV.5.3.3, if any, to reduce regulatory asset balances associated with SIR activities.

6. <u>Electric and Common Capital Investment Levels and Infrastructure and Operations Programs</u>

6.1. Electric Capital Investment Levels

Appendix 1, Schedule 5 sets forth the Company's forecast level of electric and common capital investments and cost of removal (where applicable) for each Rate Year. The electric and common capital expenditures listed in Appendix 1, Schedule 5 also include cost of removal associated with existing plant that is being retired in connection with the CLCPA Phase 2 and Smart Path projects described more fully in Section IV.6.1.2 and shown in Appendix 1, Schedule 5a because such cost of removal is not recovered through rates approved by FERC. Notwithstanding the specified segment-level spending amounts set forth in Appendix 1, Schedule 5, nothing in this Joint Proposal is intended to limit Niagara Mohawk's flexibility during the term of the rate plan to substitute, change, or modify its capital projects. As discussed more fully in Section IV.11.1.11, the Company will continue to implement a downward only electric net utility plant and depreciation expense reconciliation mechanism during the term of the rate plan.

6.1.1. EV Charging and EV School Bus Projects

The electric and common capital projects set forth in Appendix 1, Schedule 5 do not include EV charging and EV School Bus projects. The Company may propose to recover the cost of those projects in the Make-Ready Proceeding or the Proactive Planning Proceeding.[13] The Company will collaborate with interested stakeholders in those cases to consider expanding investments in EV charging beyond highway service plazas where the Company expects load growth from that particular investment.

6.1.2. CLCPA Phase 2/Smart Path Connect Projects

The electric and common capital projects set forth in Appendix 1, Schedule 5, page 1 do not include CLCPA Phase 2 and Smart Path Connect projects. These capital projects are listed in Appendix 1, Schedule 5a for transparency. The Company will track the costs and revenues associated with the Smart Path Connect and CLCPA Phase 2 projects and include such information in the quarterly electric capital reports described in Section IV.6.6.

6.2. Vegetation Management

The Company's electric revenue requirements reflect costs for vegetation management of $87.387 million in Rate Year One, $89.902 million in Rate Year Two, and $91.857 million in Rate Year Three. These costs will remain subject to a downward-only reconciliation mechanism applied to the Company's aggregate total vegetation management costs over the term of the rate plan. Any under-expenditure in total program costs in a given Rate Year will be carried forward

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[13] Case 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure ("Make-Ready Proceeding"); Case 24-E-0364, In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure ("Proactive Planning Proceeding").

and reconciled at the end of Rate Year Three. An example of the reconciliation is set forth in Appendix 5, Schedule 15.

6.2.1. Vegetation Management Reporting

Beginning in Rate Year One, the Company will commence filing quarterly reports concerning its Vegetation Management and Hazard Tree Removal Program. The reports, which will be filed no later than 60 days after the end of the calendar quarter will set forth (i) planned and actual miles of trimmed vegetation, (ii) budgeted and actual expenses by month and by division for the transmission and distribution Vegetation Management program, and (iii) budgeted and actual expenses for each program component within the Vegetation Management program that does reflect costs per mile. For the Hazard Tree Removal program, the Company will provide the planned and actual trees removed, the budgeted and actual expenses, and the average cost of each type of tree removed in each quarter.

6.3. Major Storms

For cost recovery and deferral purposes, the definition of a "Major Storm" will be that currently set forth in 16 NYCRR § 97.1(c) ("A major storm is a period of adverse weather during which service interruptions affect at least 10 percent of the customers in an operating area and/or result in customers being without electric service for durations of at least 24 hours"). During the term of the rate plan the deferral threshold for a major storm will be $0.750 million to be applied to all qualifying regions, in aggregate, in the Company's service territory for a given storm event. The Major Storm revenue allowance reflected in rates will be $78 million. The treatment of Major Storm costs is more fully described in Appendix 13 and Appendix 5, Schedule 16.

6.4. Minor Storms and Silver Lining Storms

The Company's electric revenue requirement reflects a minor storm rate allowance of $80.3 million in Rate Year One, $85.7 million in Rate Year Two, and $87.6 million in Rate Year Three.

6.4.1 Rate Year One – Total Minor Storm Reconciliation

In Rate Year One, minor storm costs will be subject to the following reconciliation:

(i) If the Company incurs less than $80.3 million of minor storm costs, the difference between the actual minor storm costs and $80.3 million will be deferred for return to customers.

(ii) If actual minor storm costs in Rate Year One are greater than $80.3 million by up to $10 million, there will be no reconciliation ($10 million upward deadband).

(iii) If actual minor storm costs in Rate Year One exceed $80.3 million by more than $10 million, the Company will defer 90 percent of the amount in excess of the $10 million upward deadband for future recovery from customers (90/10 customer/Company sharing above $10 million deadband).

6.4.2 Rate Years Two and Three – Silver Lining Storm Reconciliation

Beginning in Rate Year Two, the minor storm deferral will be modified such that the Company will only be able to defer minor storm costs associated with Silver Lining Storms as described more fully below.

The interruption time period for what may later be defined as a Silver Lining Storm together with the costs associated with those events are not defined at this time and must be developed based on data collected by the Company in Rate Year One. To that end, before the beginning of Rate Year One, the Company will update its accounting processes and procedures to track and report any storm event that could possibly qualify as a Silver Lining Storm. Within 45 days after the end of Rate Year One, the Company and Staff will meet and work collaboratively and in good faith to define a Silver Lining Storm and split the minor storm rate allowance into Silver Lining Storm costs, which are subject to deferral, and All Other Minor Storm costs, which are not subject to deferral, using the data tracked by the Company in Rate Year One.

The specifics of the Silver Lining Storm mechanism, collaborative process, and reporting are set forth in Appendix 13 and in Appendix 5, Schedule 16.

In the event the Company is unable to perform the accounting process and procedure modifications needed to identify "silver lining storm" costs for deferral treatment (*i.e.,* the Company was unable to perform all of the modifications needed to allow the recording and tracking of minor storm costs, or the Company and Staff fail to agree upon the ratio of "silver lining storms" after good faith efforts), the Silver Lining Storm deferral will dissolve and there will be no minor storm deferral. The minor storm rate allowance will remain at $85.7 million for Rate Year Two and $87.6 million for Rate Year Three with no deferral for any expenditures for the remainder of the rate plan.

6.5. Pre-Staging Storm Costs

The Company is authorized to charge the major storm reserve for pre-staging and mobilization costs incurred in reasonable anticipation that a storm will affect its electric operations to the degree of meeting the criteria of a major storm, but which ultimately does not do so. The Company can charge the following incremental costs: contractors and/or utility companies providing mutual assistance (including the costs of crews from affiliate companies), employee labor, meals, lodging, and mutual aid travel to and from National Grid's service territory.

Incremental pre-staging costs less than $0.250 million per storm event will be charged to minor storm expense. If incremental pre-staging costs for a particular storm event reach $0.250 million, then 100 percent of the incremental pre-staging costs up to $1.5 million will be charged to the major storm reserve. To the extent incremental pre-staging costs for a particular storm event exceed $1.5 million, then the Company will also charge 85 percent of the incremental pre-staging costs greater than $1.5 million to the major storm deferral and 15 percent to minor storm expense.

With the conversion of the minor storm deferral to the Silver Lining Storm deferral beginning in Rate Year Two, prestaging costs that cannot be charged to the Major Storm reserve will not be included in Silver Lining Storm costs, but will be tracked and included within all Other Minor Storms costs identified in Rate Year Two and Rate Year Three, as well as in the tracked data for Rate Year One used to calculate the Silver Lining Storm ratio. If an agreement on the definition of Silver Lining storms is not reached after Rate Year One, all pre-staging costs not attributable to the major storm reserve will remain categorized under Other Minor Storms for tracking purposes. As a result, the minor storm deferral for Silver Lining costs will be discontinued.

6.6. Electric Capital Reporting Requirements

The Company will provide quarterly and annual capital reports within this rate case on a Fiscal Year basis as follows:

(i) Annual Transmission and Distribution Capital Investment Plan (commonly referred to as the Five-year CIP) filed annually, which will include:

a. The Company's projected five-year capital investment plan on the electric transmission, sub-transmission, and distribution system.

b. Details on major projects[14] including:

i. Annual investment amounts for the period covered by the plan.

ii. Primary investment drivers and customer benefits.

iii. Schedules.

c. The Five-year CIP will be filed with the Secretary annually by January 31.

(ii) Annual Capital Investment Plan Quarterly Report, filed quarterly, which includes the following:

a. Budget variance reports (actual spending vs. approved annual budget for total electric delivery system capital investment, and segregated by transmission, sub-transmission, and distribution).

b. The Company shall provide updated in-service schedules for all electric projects having a Project Data Sheet ("PDS") in accordance with the capital expenditures agreed upon in the Joint Proposal taking into account that in the process lower priority projects or portions of projects selected by the Company will need to be reduced, eliminated, or postponed.

c. For "major" projects:

i. Budget changes or project cost overruns that require management approval.

ii. Schedule changes (and reasons for changes) for major projects, including updated project in-service dates.

d. For completed projects:

i. Comparison of initial budget vs. actual capital expenditures.

ii. Comparison of projected vs. actual in-service date.

[14] "Major" projects are individual distribution or sub-transmission projects with spend of more than $1 million in any fiscal year, and individual transmission projects with spend of more than $1 million overall.

e. Climate Leadership and Community Protection Act Phase One projects[15] will be included in the Quarterly reports regardless of the level of spending or status.

f. On or about the date of each Quarterly report filing, the Company will submit to Staff copies of all sanction papers approved for major projects during the relevant quarter and any supporting workpapers.

g. Each Quarterly report will be filed 45 days following the end of each Fiscal Year quarter.

(iii) Distributed System Implementation Plan ("DSIP"), filed every other year in this rate case, in accordance with Commission orders issued in Cases 14-M-0101 and 16-M-0411.

(iv) Report on Conditions of Physical Elements of Transmission and Distribution Systems (also known as the Asset Condition Report) filed every other year, and in the same year in which the Company files its Distributed System Implementation Plan. The Report will continue to relate inspection findings, testing and monitoring of the Company's transmission, sub-transmission, and distribution systems to the capital plan. The Asset Condition Report will be filed by October 1 in the year it is filed.

The Company will eliminate its 15-year System Plan.

6.7. Non-Wires Alternatives

The Company will continue to amortize all NWA project costs over a ten-year period. In addition, the existing NWA incentive and cost recovery mechanisms[16] will continue for the term

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[15] As outlined in the Phase I Order. Case 20-E-0197, Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, Order on Phase 1 Local Transmission and Distribution Project Proposals (issued February 11, 2021) ("Phase I Order").

[16] The existing NWA incentive and cost recovery mechanisms do not distinguish between small and large NWAs.

of the rate plan. The treatment of the NWA incentive mechanism is more fully described in Appendix 10.

6.8. NYSEIA Self-Performance of Distribution Upgrades Program

The Company will develop and implement a Self-Performance of Distribution Upgrades program (referred to as the "Program") to enable DER interconnection customers to self-perform elements of distribution upgrades, including engineering, procurement, and construction. Self-performed distribution upgrades must meet or exceed the Company's technical standards, contractor requirements, and meet Prevailing Wage requirements and otherwise comply with all laws and regulations that would be applicable if the work was performed by the utility.

The Company will first present a framework and implementing documentation for the Program at the Interconnection Policy Working Group ("IPWG") and Interconnection Technical Working Group ("ITWG") for stakeholder discussion and Staff input. The framework and implementing documentation will identify the roles/responsibilities of the utility and the interconnection customer and set forth clearly-defined practices and procedures necessary for the safety of personnel and system infrastructure, and will describe the opportunity for interconnection customers to perform work on deenergized lines, including point of interconnection facilities and express feeders, subject to limitations regarding substation work, meter/test/relay commissioning work, transmission-level work, and other types of work to be identified by the Company.

Following the stakeholder review, and after consulting with Staff, the Company will file the framework and implementing documentation for the Program with the Secretary in this case within six months of an order approving the Joint Proposal and at least 30 days before the Program becomes effective. The costs associated with implementing the Self-Performance of Distribution

Upgrades Program, if any, will be allocated to and recovered from participating interconnection customers. The Program will include a planned effective date within Rate Year One. The Company will consider self-performance proposals it receives pursuant to the Program implementation framework from the effective date of the Program until the earlier of the effective date of any subsequent statewide framework for self-performance of distribution upgrades authorized by the Commission or the end of Rate Year Three.

6.9. NYSEIA N-1 Assessment of Distributed Energy Resources ("DER") Hosting Capacity at Multi-Bank Substations

Within six months of a Commission Order approving the Joint Proposal, the Company will evaluate automatic tripping and other smart grid solutions for N-1 contingency scenarios, and identify solutions eligible for use on its electric power system. If automatic tripping and other smart grid solutions can be implemented to increase the cost-effective DER hosting capacity of substations, the Company will notify DER interconnection customers with active queue positions that are not already in construction, who may be eligible for lower cost interconnections. If a developer requests and funds a restudy of their Coordinated Electric System Interconnection Review ("CESIR"), and agrees to fund the automatic tripping or other solution, the Company will conduct a new CESIR, per the Standardized Interconnection Requirements, reflecting the change and adjust the amount of the developer's interconnection deposit. Following the six-month evaluation period, the Company will consider eligible automatic tripping or other smart grid solutions as well as traditional upgrades when conducting CESIR studies, and also will update its online hosting capacity maps to indicate areas in the system where automatic tripping or other smart grid solutions may be suitable. The Company will provide DER interconnection customers with the least cost interconnection option that has been evaluated by the Company to maintain the safety and reliability of the electric power system along with all the information required by the New York State Standardized Interconnection Requirements.

6.10. Battery Storage

Battery Storage projects included in the electric and common capital investment forecast will support the Company's distribution system. During the term of the rate plan, the Company will not sell or bid these projects into the wholesale electric market. At the end of the rate plan, if the Company intends to bid the projects into the wholesale electric market, it will file a petition with the Commission, in the Energy Storage Proceeding, requesting authorization.[17] The Signatory Parties retain their rights to take any position they deem appropriate in response to such petition.

7. Gas Capital Investment Levels and Infrastructure and Operations Programs

7.1. Gas Capital Investment Levels

Appendix 1, Schedule 5 sets forth the Company's forecast level of gas capital and cost of removal (where applicable) investment by program for each Rate Year. Notwithstanding the specified segment-level and program/project level spending amounts set forth in Appendix 1, Schedule 5, nothing in this Joint Proposal is intended to limit Niagara Mohawk's flexibility during the term of the rate plan to substitute, change, or modify its capital projects. As discussed more fully in Section IV.11.1.17, the Company will continue to implement a downward only Gas Net Utility Plant and Depreciation Expense Reconciliation Mechanism during the term of the rate plan.

[17] Case 18-E-0130, In the Matter of Energy Storage Development Program ("Energy Storage Proceeding").

7.2. PL-16 Pipeline Integrity Verification Project

PL-16 is a 41-mile pipeline running through the Company's service territory. Based on the results of the Company's most recent class locations study, the Company may be required to replace approximately 7.54 miles of the pipeline with new pressure-tested 24-inch pipe that meets the current class location testing requirements in accordance with the Commission's safety regulations. At the same time, the Company has filed a petition with the Commission requesting that the Commission approve proposed risk control activities that would eliminate the need for the Company to replace portions of PL-16.[18] The petition is pending before the Commission.

The Rate Year revenue requirement does not include the capital expenditures associated with the replacement of any portion of PL-16. Instead, the Company will be permitted to establish the PRP Surcharge to recover the revenue requirement (*i.e.,* return on investment and return of investment) associated with up to $297.4 million of capital costs forecasted to be incurred by the Company during the term of the rate plan to replace portions of PL-16, if such plant investments are placed into service. To the extent that a Commission order in Case 24-G-0183 requires the Company to undertake capital costs to address PL-16, the Company will undertake reasonable efforts to minimize capital expenditures associated with the PL-16 project consistent with the timing and substance of the Commission's order and the PRP Surcharge will be updated to permit the Company to recover its reasonable costs of complying with the Commission's order in Case 24-G-0183; however, the allocator used to apportion costs among service classifications and the

[18] Case 24-G-0183, Petition of Niagara Mohawk Power Corporation d/b/a National Grid for a Waiver of the Requirements of 16 NYCRR, Section 255.611(a) and 255.611(d) to Permit the Company to Be Exempt from Certain Class Location Requirements Related to Pipeline 16 and Extend the 18-month Period Until 2026, Petition Cover Letter (filed March 29, 2024).

maximum capital costs eligible for recovery of $297.4 million during the term of the rate plan will remain unchanged. Any changes to the project scope and costs associated with any Commission order in Case 24-G-0183 will be filed in these proceedings within 90 days of the issuance of that order with a full explanation of the changes. In addition, the Signatory Parties understand and agree that to the extent that the Commission does not grant the Company's petition in Case 24-G-0183, the Company forecasts that it will incur PL-16 replacement project costs beyond the term of the rate plan. The Company will undertake reasonable efforts to minimize capital expenditures associated with the PL-16 project. The Company may propose to recover such costs in a future rate filing.

If it is determined that the Company will not be required to undertake the PL-16 project, then the Company is authorized to include in the PRP Surcharge the preliminary engineering and development costs of the PL-16 project up to a cap of $1 million. Any surcharge established to recover PL-16 costs would utilize a peak sendout allocator to apportion costs among the Company's service classifications. An example of the surcharge is provided in Appendix 3, Schedule 13.

7.3. PL-E18 Pipeline Integrity Verification Project

The PL-E18 project entails the possible replacement of approximately ten miles of 16-inch transmission pipeline to comply with pipeline safety requirements established in 2019 by the Pipeline and Hazardous Materials Safety Administration ("PHMSA").[19] The capital expenditures

[19] The PL-E18 projects include the "Pipeline Integrity-IVP-PL-E18-MAOP Reconfiguration" and "Pipeline Integrity – IMP-PL-18 Capital Portions of Pressure Testing" projects. Costs associated with the "Pipeline Integrity-IMP-PL-E18-ILI Enable Launch and Putnam Road to Vley Road" and "Pipeline Integrity-IMP-PL-E18 Pipeline ILI Enable (Mohawk River and I890 HDD)" projects are included in the revenue requirement as they are not related to the PHMSA MAOP determination.

associated with the PL-E18 project total approximately $348.3 million over the period FY25 through FY29. These costs are not included in the revenue requirements set forth in the Joint Proposal. Rather, if the PL-E18 project is ultimately required to be undertaken by PHMSA to comply with PHMSA's requirements, the Company is permitted to recover the revenue requirement (*i.e.,* return on investment and return of investment) associated with up to $348.3 million of capital costs incurred by the Company during the term of the rate plan associated with these projects through the PRP Surcharge, if such plant investments are placed into service. The Signatory Parties understand and agree that if the Company is required to undertake the PL-E18 project, the Company will incur project costs beyond the term of the rate plan. The Company will undertake reasonable efforts to minimize capital expenditures associated with the PL-E18 project. The Company may propose to recover such costs in a future rate filing.

In determining whether it needs to proceed with the PL-E18 project during the term of the rate plan the Company will re-evaluate and/or re-assess all methods for complying with the PHMSA standards with respect to Maximum Allowed Operating Pressure ("MAOP") as set forth in 16 NYCRR §255.624. Those methods are as follows: 1) the Company could conduct a pressure test to reestablish the MAOP; assuming all other material records are in place, this method would involve pressure testing the relevant sections of pipeline to 1.5 times the required MAOP or the class location factor; 2) the Company could reduce the pressure, as necessary and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the five years preceding October 1, 2019, divided by the greater of 1.25 or the applicable class location factor; 3) the Company could conduct an engineering critical assessment in accordance with 16 NYCRR §255.632; 4) the Company could replace the pipe and document the required pressure testing of the replacement pipe; 5) the Company could implement pressure reduction for pipeline segments with small potential impact radii of less than or equal to 150 feet, and reduce the MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the five years preceding October 1, 2019, divided by 1.1, along with increasing patrols and leakage surveys; or 6) the Company could use an alternative technical evaluation process that provides a documented engineering analysis beginning within one year from the issuance of the Commission order in this case and thereafter annually. The Company will formally report its findings concerning this re-evaluation with the Commission's Secretary on or before April 1 of each Rate Year beginning in Rate Year Two.

If it is determined that the Company will not be required to undertake the PL-E18 project, then the Company is authorized to recover through the PRP Surcharge the preliminary engineering and development costs of the PL-E18 project up to a cap of $5 million. Any surcharge amount to recover PL-E18 project cost would use the peak sendout allocator to apportion the costs among the Company's services classifications.

Additional details on the surcharge are included in Appendix 3, Schedule 13.

7.4. East Gate Reliability Assessment

Costs for any East Gate Reliability Assessment are not included in the revenue requirements set forth in the Joint Proposal. If the Commission directs the Company to perform an East Gate Reliability Assessment, which is an analysis of demand-side management options that could reduce demand in the Company's East Gate supply region, in another proceeding, including but not limited to the Gas Planning Proceeding or the Long-Term Planning Proceeding, then the Company will be permitted to defer for future recovery from customers up to $7.7 million of costs associated with such assessment.[20]

7.5. Energy Transfer Station Site 2 and Moreau Injection Facility Compressed Natural Gas /Renewable Natural Gas Injection

The Company will not recover from customers any costs for Renewable Natural Gas ("RNG") injection facilities that the Company plans to construct and operate at its Energy Transfer Station ("ETS") Site 2 during the term of the rate plan. The Company will be permitted to assess fees from RNG suppliers who wish to inject RNG into the Company's ETS facility during the term of the rate plan. These fees will be determined on a negotiated basis between the Company and RNG suppliers.

The Company's total recoverable capital investment made up to and through the term of this rate plan for RNG-related equipment at the Moreau Injection Facility shall not exceed $2.5 million. To the extent the Company receives fees from the ETS facility, the Company will use up to $2.5 million of any such fees to offset the revenue requirement associated with the RNG capital investment at the Moreau Injection Facility. The Company will be permitted to retain any fees collected above the Moreau-related costs reflected in the revenue requirement for the benefit of shareholders and such fees will be accounted for on a "below-the-line" basis for ratemaking purposes in future rate proceedings.

[20] Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures (Gas Planning Proceeding); Case 24-G-0248, In the Matter of a Review of the Long-Term Gas System Plans of The Brooklyn Union Gas Company d/b/a National Grid NY, KeySpan Gas East Corporation d/b/a National Grid, and Niagara Mohawk Power Corporation d/b/a National Grid ("Long-Term Planning Proceeding").

7.5.1. ETS Site 2 Locations

The Company will not locate the ETS Site 2 within one mile of a DAC as determined at the time of construction.

7.5.2. CNG and RNG Supply Deliveries

In procuring Compressed Natural Gas ("CNG") and RNG for delivery by truck to the Company's CNG and RNG injection facilities, the Company will request transporters to develop delivery routes that avoid the highest population centers, areas known to have potential sensitive receptors such as hospitals, schools and nursing homes, and places where high density crowds are expected to be present. The Company will also seek to procure CNG and RNG supply transport services from providers using zero-emission vehicles, subject to such services being available and generally comparable to other transport service with respect to other relevant qualifications that include but are not limited to, safety, reliability, driver qualifications, scheduling, and cost.

7.5.3 RNG Interconnections

Except as set forth in Section 7.5 above, the rates established in this proceeding do not contain any costs for RNG interconnections. The costs of any RNG interconnections constructed during the term of the rate plan will be paid by RNG suppliers unless otherwise directed by the Commission.

7.6. Gas Capital Reporting Requirements

7.6.1. Leak Prone Pipe Prioritization, Type 3 Leak, and Capital Plan Report

On or before April 1 of each year, the Company will file with the Secretary to the Commission a LPP prioritization summary identifying: (i) the proposed projects and their estimated costs; (ii) an inventory of Type 3 leaks on its system; and (iii) the approved five-year capital plan in the same format as Appendix 1, Schedule 5.

7.6.2. Quarterly Capital Report

The Company will file with the Secretary to the Commission a quarterly variance report within 45 days after the end of each of the first three quarters of each Fiscal Year. The report will be in the same format as Appendix 1, Schedule 5 with explanations for variances between the approved budget and the actual expenditures, details on the progress of LPP retirement mileage, Type 3 leaks repaired, and a summary of the current Type 3 leak inventory, and new customers connected to the system.

7.6.3. Annual Capital Report

The Company will file with the Secretary to the Commission an annual report not later than May 31 of each year that includes, for the preceding Fiscal Year: (i) a final variance summary of capital expenditures for all capital projects and programs, including all ongoing and active construction projects and programs in the same format as Appendix 1, Schedule 5; (ii) a narrative explaining any cost or timeline differences exceeding 10 percent; (iii) a narrative on project design, permitting, and/or construction status (including a detailed construction schedule for each project) for any ongoing projects; (iv) a description of any new projects or programs; and (v) capital project sanctioning documents for any projects exceeding $1 million that were authorized during the previous Fiscal Year.

7.7. Residential Methane Detectors

The Company will be permitted to recover costs associated with the installation of 4,000 Residential Methane Detectors ("RMDs") in Rate Year One, 12,000 in Rate Year Two, and 24,000 in Rate Year Three as follows:

(i) in Rate Year One, the Company will use existing deferred Negative Revenue Adjustment ("NRA") credit balances, except for the NRA credit balance created as a result of the Commission's December 20, 2024 order in Case 24-G-0592, to fund the revenue requirement associated with the forecast RMD installations; and

(ii) in Rate Years Two and Three the revenue requirements reflect funding for the forecast RMD installations.

7.8. Damage Prevention Costs

The Company will utilize existing NRA balances to offset its damage prevention costs in Rate Year One. Damage Prevention Costs in Rate Years Two and Three are included in the revenue requirements.

8. <u>Advanced Metering Infrastructure</u>

8.1. Downward-Only Tracker for Operation and Maintenance Costs

In the 2022 Rate Order, the Company was authorized to recover $119.17 million of AMI-related O&M expense incurred during the six-year AMI deployment period beginning Fiscal Year 2022 subject to a downward only reconciliation at the end of the six-year AMI deployment period. This downward only tracker, as set forth in the Joint Proposal approved by the 2022 Rate Order, will continue during the term of the rate plan.

8.2. Miscellaneous AMI-related Matters

8.2.1. Resiliency Enhancements to AMI Communications System

The revenue requirement reflects the recovery of $7.75 million of incremental AMI-related capital expenditures in Rate Year One for AMI storm hardening battery packs. These capital expenditures will be considered to be outside the cost cap on AMI-related capital expenditures established by the Commission in the AMI Implementation Order.[21] The Company will continue to evaluate opportunities to enhance resiliency through development of the AMI deployment plan.

8.2.2. Potential Incentives Under the AMI Project

The Company will consider AMI project incentives and may propose incentives in its next base rate filing.

9. Information Technology and Digital

9.1. Information Technology and Digital Capital Investment Level

Niagara Mohawk's rates include costs associated with Information Technology and Digital ("IT&D") capital investments that are owned by National Grid USA Service Company, Inc. ("Service Company") and allocated to Niagara Mohawk in the form of rent expense. Rent expense includes the return on, and the amortization or depreciation of current IT&D capital investments along with incremental IT&D capital investments that are forecast for the Rate Years. Appendix 1, Schedule 7 sets forth the IT&D capital investment plan by program.

[21] Case 17-E-0238, Niagara Mohawk Power Corporation d/b/a National Grid Rate Case, Order Authorizing Implementation of Advanced Metering Infrastructure with Modifications (issued November 20, 2020) ("AMI Implementation Order").

The schedules set forth actual capital spending through March 31, 2025 and incremental capital spending from April 2025 through the end of each Rate Year. Notwithstanding the specific program level spending amounts shown in Appendix 1, Schedule 7, nothing in this Joint Proposal is intended to limit the Company's flexibility during the term of the rate plan to substitute, change or modify capital projects. The Company will continue to implement a downward-only Service Company Rents IT&D Net Utility Plant and Depreciation Expense Reconciliation Mechanism during the term of the rate plan as described more fully in Section IV.11.1.20 of this Joint Proposal.

9.2 IT&D Capital Reporting

The Company will conform its IT&D Capital Report to the reporting requirements that will be implemented for the Company's affiliates, The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid, as set forth in the "Information Technology and Digital Reporting Format" report dated March 28, 2025 and filed with the Commission in Cases 23-G-0225 and 23-G-0226.

10. Street Lighting

10.1. Street Lighting Rate Design

Niagara Mohawk's street lighting rate design is set forth on Appendix 2, Schedule 8.1.

10.2. SC-2 Pricing Exception

The SC-2 Pricing Exception facility prices in the Company's P.S.C. No. 214 – Outdoor Lighting Tariff ("Outdoor Lighting Tariff") will continue to be eliminated over a 10-year period as approved by the Commission in the 2022 Rate Orders.

10.3. Outage Credit Allowance

The Outage Credit Allowance for SC-2 and SC-3 in the Outdoor Lighting Tariff will be updated as shown in Appendix 2, Schedules 8.4a, 8.4b, and 8.4c.

10.4. Lighting Service Charges

The Company will update the SC-2 and SC-3 lighting service charges in the Outdoor Lighting Tariff as shown in Appendix 2, Schedules 8.5.

10.5. Elimination of SC-6

SC-6 will be closed and removed from the Outdoor Lighting Tariff as of the beginning of Rate Year One.

10.6. Electric Service Tariff Revisions Associated With Outdoor Lighting

The Company will modify Rule 32 of its Electric Service Tariff to add a subpart to exclude overhead lighting facilities from the calculation of charges for municipal undergrounding.

10.7. New Outdoor Lighting Facilities Offerings

Beginning in Rate Year One, the Company will implement the following new facility offerings with rates as detailed in the Company's Exhibit ___ (E-RDP-8), Schedules 5.1 and 5.2 to its May 28, 2024 filing in this proceeding:

(i) add four underpass light emitting diode ("LED") luminaries to replace the existing high-intensity discharge ("HID") underpass luminaires;

(ii) add four 3,000 correlated color temperature roadway luminaries; and

(iii) implement an alternatively sourced convenience outlet device known as Power Tap.

10.8. Miscellaneous Outdoor Lighting Tariff Changes

The Company will modify its Outdoor Lighting Tariff in the following manner:

(i) to modify or add abbreviations and definitions of

1. CCT – Correlated Color Temperature
2. CIAC – Contribution In Aid of Construction
3. IESNA/IES – Illuminating Engineering Society of North America
4. "NEMA –National Electric Manufacturers Association"
5. Direct Buried Cable
6. Supplemental Attachment
7. Ancillary Equipment

(ii) to include language on Leaf 9.2 to incorporate various surcharges in the Outdoor Lighting Tariff;

(iii) to revise Leaf 9.5.1 – Underground Electric Distribution System Infrastructure – to define, describe and differentiate the appropriate application of the Company's undergrounding rule and the termination of lighting facilities;

(iv) to revise Leaf 9.6 Billable Wattage – to specify differences in billing for SC-3, as opposed to the terms set for SC-1 and SC-2;

(v) to revise Leaf 9.6.2 – Volumetric Chargers, Adaptive Hours of Operations for SC-3 to update the definition of the minimum period charges shall remain in effect and sets forth the terms under which a charge can occur as well as the application of technological changes of ancillary motion sensors;

(vi) to revise Leaf 10 to the provisions that define supplemental attachments;

(vii) to revise Leaf 12 – Facility Service Limitations to specify that customers can request general luminaire operating performance criteria.

(viii) to revise SC-1 to make corrections associated with changed component facility classifications and HID luminaires that have been eliminated from stock;

(ix) to revise SC-2 to address the management of unique customer account situations, the addition of proposed new facilities and the removal of closed or obsolete facilities; and

(x) to revise SC-3 to clarify that the Company has no obligation to purchase any customer owned street light systems, to correct the Hours of Operation table, to clarify the billing and servicing of supplemental attachments, and to reflect the elimination of Schedule SL-3 for the Outdoor Lighting Tariff.

11. <u>Electric and Gas Reconciliations, Deferrals, and True-Ups</u>

11.1 Existing Electric and Gas Reconciliations, Deferrals, and True-Ups

Appendix 5, Schedule 1 and Appendix 6, Schedule 1 set forth the electric and gas deferral accounts and other regulatory assets and liabilities balances, respectively, as of December 31, 2023. With the exception of the deferral accounts and other regulatory assets and liabilities identified as "Discontinued," Niagara Mohawk is authorized to continue using reconciliation mechanisms and/or deferral accounting (with certain modifications) with respect to the electric and gas expenses set forth in Appendix 5, Schedule 1 and Appendix 6, Schedule 1.[22]

[22] The deferral accounts and other regulatory assets and liabilities identified as "Discontinued" will be discontinued as of the Effective Date. These accounts contain forecast balances as of March 31, 2025, which are set forth in Appendix 5, Schedule 1 and Appendix 6, Schedule 1. The discontinuance of these accounts is not intended to preclude the Company from returning to or recovering from customers the balances as of March 31, 2025 plus any applicable carrying charges.

Except where otherwise noted, Niagara Mohawk will accrue carrying charges on all electric and gas deferral accounts and other regulatory assets and liabilities, net of deferred taxes, using the pre-tax weighted average cost of capital for the respective Rate Year.[23] An example of the calculation of carrying charges is set forth in Appendix 5, Schedule 2 for electric and Appendix 6, Schedule 2 for gas.

11.1.1. Pension and Other Post-Employment Benefit Expenses (Electric and Gas)

Niagara Mohawk will continue to defer and reconcile its actual electric and gas pension and Other Post-Employment Benefit ("OPEB") expenses to the levels allowed in rates (set forth in the tables below) in accordance with the Commission's Pension & OPEB Statement of Policy.

Pension Expense	Rate Year One	Rate Year Two	Rate Year Three
Electric	($2.582) million	($0.612) million	$0.603 million
Gas	($0.515) million	($0.137) million	$0.106 million

OPEB Expense	Rate Year One	Rate Year Two	Rate Year Three
Electric	($25.159) million	($27.834) million	($21.043) million
Gas	($4.792) million	($5.311) million	($4.013) million

Carrying charges will not be calculated on pension or OPEB deferred balances that represent the difference between the Company's actual expenses and the amounts reflected in rates. An example of the reconciliation is set forth in Appendix 5, Schedule 3 for electric and Appendix 6, Schedule 3 for gas.

The Signatory Parties acknowledge that the revenue requirements in this Joint Proposal reflect negative pension/OPEB expense and create a cash shortfall of ($15.0 million) in Rate Year

[23] This applies to deferred balances referenced in other sections of this Joint Proposal unless specifically stated otherwise.

One, ($14.4 million) in Rate Year Two, and ($4.5 million in Rate Year Three),[24] which creates the need for internal reserve debit balances to pension and OPEB expenses consistent with the Commission's Pension & OPEB Statement of Policy. As shown in Attachment A to Appendix 9, the revenue requirements set forth in this Joint Proposal reflect an Earnings Base/Capitalization ("EB/CAP") adjustment to permit the Company to recover the equivalent of carrying charges on the internal reserve debit balances through the end of Rate Year Three. The ratemaking and accounting treatment for the internal reserve is detailed in Appendix 9. Notwithstanding the rate treatment for pension and OPEB expense provided for under this Joint Proposal, the Company will be permitted to petition the Commission during the rate plan to adjust the rate allowance for pension and OPEBs in order to address any known or imminent negative impacts on the Company's credit rating and/or financial condition, that if not addressed, could lead to a downgrade of its credit ratings. The Signatory Parties retain their rights to take any position they deem appropriate in response to such petition.

11.1.2. Energy Affordability Program (Electric and Gas)

The Company will continue to implement its electric and gas EAP as set forth in Section IV.14.1 of this Joint Proposal. EAP costs consist of two components: (i) an annual amount reflected in the revenue requirements, and (ii) an incremental amount reflecting the change in the EAP discount amount from the rate increase for each rate year (collectively, the "Total Rate Allowance"). The latter component is reflected through the revenue allocation and rate design process. The EAP Total Rate Allowances are $61.775 million in Rate Year One, $87.575 million

[24] The cash shortfall is equal to the difference between the negative expense levels reflected in the revenue requirements and the inverse of the capitalized expenses.

in Rate Year Two, and $94.324 million in Rate Year Three for the Company's electric business, and $10.404 million in Rate Year One, $16.060 million in Rate Year Two, and $20.717 million in Rate Year Three for the Company's gas business.[25] Each Rate Year, the Company will fully reconcile EAP costs to the Total Rate Allowance. Amounts in excess of the Total Rate Allowance will be deferred for future recovery from customers. Any under-expenditures will be deferred for future use in a low-income assistance program. An example of the reconciliation is set forth in Appendix 5, Schedule 4 for electric, and in Appendix 6, Schedule 4 for gas.

11.1.3. Economic Development Discount Program (Electric and Gas)

The Company will continue its electric and gas Economic Development Discount Programs, as set forth in Section IV.14.7.1 of this Joint Proposal. Each Rate Year, the Company will fully reconcile economic development discounts (*i.e.*, for electric, EJP, new discount contracts under SC-12, and existing discount contracts under SC-12; for gas, EJP discounts) to the amount reflected in rates for refund to or recover from customers. The amounts reflected in rates for economic development discounts are as follows:

Economic Development Fund Programs	Rate Year One	Rate Year Two	Rate Year Three
Electric Business	$0.959 million	$1.561 million	$4.802 million
Gas Business	$0.526 million	$0.592 million	$0.770 million

The electric and gas Economic Development Discount Programs will be a separate deferral account from the electric and gas Economic Development Grant Programs set forth below. An example of the reconciliation is provided in Appendix 5, Schedule 5 for electric, and in Appendix 6, Schedule 5 for gas.

[25] The EAP Total Rate Allowances are inclusive of April 2025 rate allowance under current rates.

11.1.4. Economic Development Grant Programs (Electric and Gas)

The Company will continue its electric and gas Economic Development Grant Programs, as described in Section IV.14.7.2. The Economic Development Grant Programs for the electric and gas businesses will be funded at $11 million and $1 million per year, respectively, subject to downward-only reconciliations over the term of the rate plan. Any difference between the respective rate allowance and actual program costs in a given Rate Year will be carried forward and reconciled at the end of Rate Year Three, with any under-expenditure to be deferred for future use in the respective Economic Development Grant Programs. The Company may petition the Commission to utilize any deferral balances related to the Economic Development Grant Programs to fund emergency economic assistance or other incremental economic development programs. The Economic Development Grant Program for gas will be funded by amortizing up to $1 million of the existing economic development programs gas deferral balance in each Rate Year. An example of the reconciliation is provided in Appendix 5, Schedule 6 for electric, and in Appendix 6, Schedule 6 for gas.

In the event of any anticipated over-expenditures, the Company may petition the Commission for deferral treatment but will have no obligation to make any additional expenditure unless and until the Commission authorizes the Company to defer amounts in excess of the three-year aggregate rate allowance for future recovery.

11.1.5. Site Investigation and Remediation Expense (Electric and Gas)

Each Rate Year, the Company will fully reconcile actual SIR expense to the annual rate allowance of $17.404 million for electric and $3.071 million for gas in Rate Year One and $17.357

million for electric and $3.063 million for gas in Rate Years Two and Three. Any under- or over-expenditures will be deferred for future refund to, or recovery from, customers. An example of this reconciliation is set forth in Appendix 5, Schedule 8 for electric and Appendix 6, Schedule 8 for gas. SIR costs are defined on Page 2 of each Schedule.

The Company will continue to submit annual reports concerning its SIR program to the Commission that will include all information provided in its current annual reports.

11.1.6. Property Tax Expense (Electric and Gas)

Each Rate Year, the Company will reconcile actual property tax expense to the rate allowance. The difference between actual property tax expense, excluding the effects of property tax refunds, and the rate allowance (set forth in the table below) will be deferred for future refund to or recovery from customers. Differences will be shared 90 percent/10 percent between customers and the Company, respectively. An example of this reconciliation is set forth in Appendix 5, Schedule 9 for electric, and in Appendix 6, Schedule 9 for gas. The Company's property tax rate allowance for its electric and gas businesses are as follows:

Property Tax Expense	Rate Year One	Rate Year Two	Rate Year Three
Electric Business	$198.943 million	$200.111 million	$209.391 million
Gas Business	$52.712 million	$54.664 million	$59.605 million

If Niagara Mohawk is successful in obtaining property tax refunds, it will have the right to petition the Commission to share in such refunds. Other parties may take any position concerning any petition filed by Niagara Mohawk.

11.1.7. Negative or Positive Revenue Adjustments (Electric and Gas)

Niagara Mohawk will defer (i) any negative revenue adjustments associated with the electric and gas Customer Service Performance Indicators and Electric Reliability Metrics (Section IV.12 of this Joint Proposal), and/or (ii) any negative or positive revenue adjustments associated with the Gas Safety Performance Metrics (Section IV.13 of this Joint Proposal).

11.1.8. Externally Imposed Costs (Electric and Gas)

One hundred percent of all Externally Imposed Costs (including any credits) associated with or caused by an individual instance (as described below) will be deferred, once such costs exceed the threshold set forth below. If Externally Imposed Costs caused by an individual instance in any one Rate Year exceed 25 basis points of return for the year in which the change first occurs, calculated and applied separately for electric and gas, and the Commission does not otherwise address the treatment of such costs (the "Externally Imposed Cost Threshold"), the total impact of the Externally Imposed Costs as applicable to the Company's electric or gas operations, respectively, will be deferred. "Externally Imposed Costs" means all of the incremental effects on Niagara Mohawk's costs, revenues, or revenue requirements above or below the amounts set forth in Appendix 1, Schedules 1 and 2, associated with or caused by an individual instance of:

a. any externally imposed accounting change;

b. any change in the federal, state, or local rates, laws, regulations, or precedents governing income, revenue, sales, or franchise taxes;

c. any refunds or payments (with interest and net of deferred taxes) reasonably made to or by Niagara Mohawk associated with electric and/or gas operations as a result of any ongoing or new examinations by federal and/or state tax authorities of Niagara Mohawk's tax returns; or

d. any legislative, court, or regulatory change that imposes new or modifies existing obligations or duties.

In addition, the Signatory Parties recognize that:

i. there are pending PHMSA rulemakings regarding pipeline integrity management, integrity verification, leak data and related issues associated with the Pipeline Safety Act of 2011 and the Protecting Our Infrastructure of Pipeline and Enhancing Safety Act of 2020;

ii. there is the potential for regulatory rulemaking by the Environmental Protection Agency and/or the Department of Environmental Conservation regarding GHG emissions and related issues (*e.g.*, New York Cap and Invest Program);

iii. there is the potential for further changes to federal and state income taxes,

iv. there is the potential for the Commission to require incremental work associated with tapping tees in Case 23-G-0083;[26] and

v. there is potential for the Commission to issue orders concerning statewide policy issues impacting gas utilities that could cause Niagara Mohawk to incur incremental costs (*e.g.*, the Gas Planning Proceeding, and the UTEN Proceeding).[27]

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[26] Case 23-G-0083, Proceeding on Motion of the Commission Regarding an Examination by Gas Distribution Utilities Concerning the Installation of PermaLock Tapping Tee Assemblies.

[27] Case 22-M-0429, Proceeding on Motion of the Commission to Implement the Requirements of the Utility Thermal Energy Network and Jobs Act (Utility Thermal Energy Network ("UTEN") Proceeding).

Should new regulations and/or legislation identified in items (i) through (v) above be enacted that affect Niagara Mohawk's costs during the term of the rate plans, Niagara Mohawk will defer all incremental costs or decreases in costs arising from such actions without regard to whether such changes exceed the Externally Imposed Cost Threshold. In the event that Externally Imposed Costs are incurred, Niagara Mohawk will file a letter with the Secretary setting forth the rationale for the deferral and its calculation. Any disagreement associated with the filing will be referred to the Commission for a decision.

11.1.9. Internally Adopted Accounting Changes (Electric and Gas)

Niagara Mohawk will notify the Director of the Department of Public Service's Office of Accounting, Audits and Finance of any significant changes to its accounting policies. Approval of the Director of the Office of Accounting, Audits and Finance is necessary before Niagara Mohawk records on its books any deferral for the net impact of an internal accounting change pursuant to this Section. If such approval is granted, the Company will be allowed to book the deferral prospectively from the date of approval, regardless of whether the accounting change was previously reflected in an account other than the deferral account. The Director of the Office of Accounting, Audits and Finance will use best efforts to rule on any request for the deferral of the impact of an internal accounting change within 90 days of submission, provided that the Company's initial submission is complete and includes full support for the accounting change and the quantification of the net impact of the accounting change, including any required offsets. Niagara Mohawk will include in the deferral account the net impact of any accounting change adopted as a matter of internal accounting policy when the accounting change, evaluated individually, increases or decreases Niagara Mohawk's costs or revenues from regulated operations or changes Niagara Mohawk's policy for capitalizing or expensing any item by more than $500,000 per year for the electric business and/or $100,000 per year for the gas business.

11.1.10. Variable Pay (Electric and Gas)

Each Rate Year, the Company will defer for refund to customers any variable pay compensation amounts reflected in rates that are not paid to employees. The rate allowance for variable pay is set forth in the table below. An example of this reconciliation is set forth in Appendix 5, Schedule 10 for electric and Appendix 6, Schedule 10 for gas.

Variable Pay Expense	Rate Year One	Rate Year Two	Rate Year Three
Electric Business	$25.614 million	$27.500 million	$28.612 million
Gas Business	$6.876 million	$7.398 million	$7.680 million

11.1.11. Electric Net Utility Plant and Depreciation Expense Reconciliation Mechanism

The Company will continue to implement a downward-only electric Net Utility Plant and Depreciation Expense Reconciliation Mechanism during the rate plan. Each Rate Year, the Company will reconcile its actual electric average net utility plant (which includes the allocation of common plant to the electric business) and depreciation expense revenue requirement to the target electric average net utility plant and depreciation expense revenue requirement, which are: $1.322 billion for Rate Year One; $1.462 billion for Rate Year Two; and $1.585 billion for Rate Year Three.

The electric average net utility plant and depreciation expense revenue requirement will be calculated by multiplying the Company's pre-tax weighted average cost of capital in the respective Rate Years by the electric average net utility plant balance, and adding this product to the electric depreciation expense.

With the exception described below regarding the implementation of NWAs, the difference between the actual electric average net utility plant and depreciation expense revenue requirement and the target electric average net utility plant and depreciation expense revenue requirement will carry forward for each Rate Year and be summed at the end of Rate Year Three. As illustrated in Appendix 5, Schedule 7, if, at the end of Rate Year Three, the cumulative actual electric average net utility plant and depreciation expense revenue requirement is negative, the Company will defer the revenue requirement impact for the benefit of customers. If, at the end of Rate Year Three, the cumulative actual electric average net utility plant and depreciation expense revenue requirement is positive, there will be no deferral.

The reconciliation mechanism will apply to the Company's aggregate total electric average net plant and depreciation expense combined, and not to individual components. The net plant target balances and reconciliation will not consider the impact of ADIT.

To the extent the Company implements an NWA that results in the displacement of a capital project reflected in the average electric net utility plant, the balance(s) will be reduced to exclude the forecast net plant associated with the displaced project. The carrying charge, or a portion thereof, as warranted, on the reduction of the average electric net utility plant that would otherwise be deferred for customer benefit will instead be applied as a credit against the recovery of the NWA, as shown in Appendix 5, Schedule 7.

11.1.12. Major Storm Expense (Electric Only)

The provisions relating to major storm expense are set forth in Section IV.6.4 of this Joint Proposal and Appendix 13. An example of the reconciliation is set forth in Appendix 5, Schedule 16.

11.1.13. Minor Storm Costs/Silver Lining Storm Costs (Electric Only)

The provisions relating to minor storm expense/Silver Lining Storm costs are set forth in Section IV.6.5 of this Joint Proposal and Appendix 13. An example of this reconciliation is set forth in Appendix 5, Schedule 16.

11.1.14. Aggregation Fee (Electric Only)

The Company will continue to accrue and amortize aggregation fee amounts collected pursuant to Rule 47 of its Electric Service Tariff. No carrying charges will be calculated for aggregation fee amounts.

11.1.15. Voltage Migration Fee (Electric Only)

The Company will continue to accrue and amortize voltage migration fee amounts collected pursuant to Rule 44.2 of its Electric Service Tariff. No carrying charges will be calculated for voltage migration fee amounts.

11.1.16. Transmission Revenue Adjustment Clause (Electric Only)

Pursuant to Rule 43 of its Electric Service Tariff, the Company will continue to reconcile the actual transmission revenue realized, exclusive of revenue taxes, to the forecast transmission revenue credit assumed in rates of $363.1 million for Rate Year One, $361.0 in Rate Year Two, and $361.0 in Rate Year Three. NYPA load (including ReCharge New York load) will continue to be subject to the TRAC. The TRAC will be subject to a monthly true-up, with any over/under collection at the end of each month to be included in the TRAC balance for refund or recovery, subject to the caps. The Company's tariff will also be modified to permit the Company to increase or decrease the TRAC cap limits to between $8 million and $16 million when the TRAC balance meets or exceeds $125 million, provided that the cap may not be increased or decreased more than

$8 million in any given month. An example of this reconciliation is set forth in Appendix 5, Schedule 14. Carrying charges will be calculated as set forth in Rule 43.5.1 of its Electric Service Tariff.

11.1.17. Gas Net Utility Plant and Depreciation Expense Reconciliation Mechanism

The Company will implement a downward-only gas Net Utility Plant and Depreciation Expense Reconciliation Mechanism. Each Rate Year, the Company will reconcile its actual gas average net utility plant (which includes the allocation of common plant to the gas business) and depreciation expense revenue requirement to the target gas average net utility plant and depreciation expense revenue requirements, which are: $327.868 million for Rate Year One; $360.947 million for Rate Year Two; and $390.693 million for Rate Year Three. The gas average net utility plant and depreciation expense revenue requirement will be calculated by multiplying the Company's pre-tax WACC in the respective Rate Years by the gas average net utility plant balance, and adding this product to the gas depreciation expense.

With the exception described below regarding the implementation of NPAs, the difference between the actual gas average net utility plant and depreciation expense revenue requirement and the target gas average net utility plant and depreciation expense revenue requirement will carry forward for each Rate Year and be summed at the end of Rate Year Three. As illustrated in Appendix 6, Schedule 7, if, at the end of Rate Year Three, the cumulative actual gas average net utility plant and depreciation expense revenue requirement is negative, the Company will defer the revenue requirement impact for the benefit of customers. If, at the end of Rate Year Three, the cumulative actual gas average net utility plant and depreciation expense revenue requirement is positive, there will be no deferral.

The reconciliation mechanism will apply to the Company's aggregate total gas average net plant and depreciation expense combined, and not to individual components. The net plant target balances and reconciliation will not consider the impact of ADIT.

To the extent the Company implements an NPA that results in the displacement of a capital project reflected in the average gas net utility plant, the balance(s) will be reduced to exclude the forecast net plant associated with the displaced project. The carrying charge, or a portion thereof, as warranted, on the reduction of the average gas net utility plant that would otherwise be deferred for customer benefit will instead be applied as a credit against the recovery of the NPA, as shown in Appendix 6, Schedule 7.

11.1.18. Net Revenue Sharing (Gas Only)

The Company's Net Revenue Sharing Mechanism set forth in Rule 26 of its Gas Service Tariff will continue. The delivery revenue service targets for SC-6, SC-9, and SC-14 have been updated for each of the Rate Years. The updated targets are set forth in Appendix 3, Schedule 8.

11.1.19. Accrued Unbilled Revenue Deferral (Gas Only)

Niagara Mohawk will continue its current deferral practice concerning accrued unbilled revenues pursuant to the Commission's August 30, 1988 Order in Case 29670. No carrying charges will be calculated for accrued unbilled revenues.

11.1.20. Service Company Rents, IT&D Net Utility Plant and Deprecation Expense Reconciliation Mechanism (Electric and Gas)

This deferral is discussed in Section IV.9.1 of this Joint Proposal. The Company will continue to implement a downward-only Service Company Rents IT&D Net Utility Plant and Depreciation Expense Reconciliation Mechanism during the term of the rate plan. Each Rate Year, the Company will reconcile its annual IT&D Program average net utility plant and depreciation expense revenue requirements to the forecast revenue requirements as set forth below and as shown in Appendix 5, Schedule 11 for the Company's electric operations and Appendix 6, Schedule 11 for the Company's gas operations. The mechanism will not continue beyond Rate Year Three except that if the Company is below its target at the end of Rate Year Three, the mechanism will continue until the targets are met.

	Rate Year One	Rate Year Two	Rate Year Three
Electric	$107.457M	$131.764M	$150.823M
Gas	$23.483M	$26.735M	$29.461M

The IT&D Program average net utility plant and depreciation expense revenue requirement will be calculated by applying the Company's pre-tax weighted average cost of capital in the respective Rate Years to the IT&D Program average net utility plant balance and adding the depreciation expense to the product. The difference between the actual IT&D Program average net utility plant and depreciation expense revenue requirement and the target average net utility plant and depreciation expense revenue requirement will carry forward for each Rate Year and be summed at the end of Rate Year Three. As illustrated in Appendix 5, Schedule 11, and Appendix 6, Schedule 11, if, at the end of Rate Year Three, the cumulative actual IT&D Program average net utility plant and depreciation expense revenue requirement is negative, the Company will defer the revenue requirement impact for the benefit of customers. If, at the end of Rate Year Three, the cumulative actual IT&D Program average net utility plant and depreciation expense revenue requirement is positive, there will be no deferral.

The reconciliation mechanism will apply to the aggregate total IT&D Program average net plant and depreciation expense combined, and not to individual components. The net plant target balances and reconciliation will not consider the impact of ADIT.

An example of this deferral is set forth in Appendix 5, Schedule 11 for electric and Appendix 6, Schedule 11 for gas.

11.1.21. Vegetation Management (Electric Only)

The Company will defer for future refund to customers any costs arising from the continued operation of its downward-only vegetation management tracker as discussed in Section IV.6.2. An example of the reconciliation is set forth in Appendix 5, Schedule 15.

11.1.22. Pre-Staging Storm Costs

The provisions relating to pre-staging storm costs are set forth in Section IV.6.5 of this Joint Proposal and Appendix 13.

11.1.23. Revenue Decoupling Mechanism (Electric and Gas)

As discussed in Sections IV.3.8 and IV.4.6 of this Joint Proposal, the Company will continue to reconcile forecast and actual revenues through its RDM during the term of the rate plan.

11.1.24. Energy Efficiency Costs

As discussed in Section IV.14.5, the Company will continue to reconcile energy efficiency program costs.

In addition, in the event the Commission changes electric and/or gas energy efficiency budgets and targets during the term of these rate plans, the Company will be permitted to defer and recover any incremental energy efficiency costs approved by the Commission through the IEE Surcharge.

11.1.25. Non-Wire Alternatives (Electric Only)

As described in Section IV.6.7, the Company will be permitted to defer and recover NWA project costs as more fully described in Appendix 10.

11.1.26. Continuing Electric Reconciliation Mechanisms

The following electric reconciliation mechanisms will continue outside of base rates:

a. System Benefit Charge ("SBC") costs, which include the Clean Energy Fund ("CEF") surcharge and the Integrated Energy Data Resource Surcharge, will continue to be reconciled pursuant to Rule 41 of its Electric Service Tariff. Carrying charges will be calculated using the other customer capital rate.

b. Pursuant to Rule 46.2.6 of its Electric Service Tariff, the Company will continue to pass the benefits associated with the net market value of NYPA Rural and Domestic Power to residential customers. No carrying charges will be calculated for this deferral balance.

c. Commodity costs will be reconciled through the Electricity Supply Reconciliation Mechanism pursuant to Rule 46.3 of its Electric Service Tariff. No carrying charges will be calculated for this deferral balance.

d. Pursuant to Rule 46.2.7 of its Electric Service Tariff, the Company will reconcile costs associated with the Nine Mile Unit #2 Power Purchase Agreement. Carrying charges will be calculated as set forth in Rule 46.2.7.

e. Purchased power contract costs will be reconciled through the Legacy Transition Charge pursuant to Rule 46.2 of its Electric Service Tariff. No carrying charges will be calculated to this deferral balance.

f. Dynamic Load Management program costs will be reconciled pursuant to Rule 64 of its Electric Service Tariff. Carrying charges will be calculated as set forth in Rule 64.

g. The MFC reconciliation, as modified in Section IV.3.9, will continue.

h. The Clean Energy Standard Supply and Delivery charges will be reconciled pursuant to Rule 46 of its Electric Service Tariff. No carrying charges will be calculated for the supply portion of this deferral balance. Carrying charges will be calculated for the Clean Energy Standard Delivery (NYSERDA Backstop costs) portion of this deferral balance.

i. Value of Distributed Energy Resources Value Stack costs will be reconciled pursuant to Rule 46 of its Electric Service Tariff. No carrying charges will be calculated for this deferral balance.

j. The EV Make-Ready Surcharge will be reconciled pursuant to Rule 52 of its Electric Service Tariff. Carrying charges at the Company's pre-tax weighted average cost of capital will be calculated for this deferral balance.

k. The Energy Storage Surcharge will be reconciled pursuant to Rule 56 of its Electric Service Tariff. Carrying charges at the Company's pre-tax weighted average cost of capital will be calculated for this deferral balance.

11.1.27. Continuing Gas Reconciliation Mechanisms

The following gas reconciliation mechanisms will continue outside of base rates:

a. The Company will continue to recover and reconcile research and development Millennium Fund costs in accordance with PSC 219 Rule 30 and the Commission's

February 14, 2000 Order in Case 99-G-1369. No carrying charges will be calculated for this deferral balance.

b. The Company will continue to recover and reconcile its cost of gas in accordance with Rule 17 of its Gas Service Tariff. Carrying charges will be calculated as set forth in Rule 17.7.2.

c. The MFC reconciliation as modified in Section IV.4.7 will continue. Carrying charges for the annual MFC reconciliation will be calculated at the other customer capital rate;

d. The LAUF reconciliation as modified in Section IV.4.5 will continue. Carrying charges for the annual LAUF reconciliation will be calculated at the other customer capital rate; and

e. The ETIP reconciliation applicable to SC-5 and SC-8 will continue to recover and reconcile energy efficiency costs included in base rates in accordance with Rule 31.2 of the Gas Service Tariff. Carrying charges will be calculated at the other customer capital rate.

11.2. New Electric and Gas Reconciliations, Deferrals, and True-Ups

The following new electric and gas deferral accounts will be implemented. Niagara Mohawk will accrue carrying charges on the new deferral account balances, net of deferred taxes, calculated using the pre-tax weighted average cost of capital for the respective Rate Year.

11.2.1. Leak Repairs (Gas Only)

As set forth in Section IV.13.2, this Joint Proposal establishes certain Total Leak performance targets for CY2025 - CY2027. If the Company is able to repair increased leaks that reduce its existing leak backlog in any Rate Year, then the Company will be permitted to defer for future recovery from customers the costs of repairing the incremental leaks. The ability to defer the costs of incremental leaks is not dependent on the Company achieving a PRA in any Rate Year.

11.2.2. Uncollectible Expenses

Each Rate Year, the Company will reconcile its actual uncollectible expense (*i.e.,* net write-offs) to the amounts reflected in electric and gas rates. The reconciliation will include the commodity portion of uncollectible expense that is recovered through the MFC and the amounts recovered through ESCOs through the Purchase of a Receivable discount, in addition to the delivery component of the uncollectible expense. If actual uncollectible expenses are lower than the amounts reflected in rates, the Company will defer for future return to customers 100 percent of the over recovery. If actual uncollectible expenses are greater than the amounts reflected in rates, the Company will defer 80 percent of the under recovery for future recovery from customers. An example of the reconciliation is set forth in Schedule 13 of Appendix 5 and Appendix 6.

11.2.3. Management and Operations Audit Expenses

Both the Company and Staff provided testimony regarding the Company's compliance with recommendations resulting from its most recent management and operations audit. In that testimony, the Company and Staff noted that in the March 2023 Letter from the Staff Director of the Office of Accounting, Audits and Finance, the Company had implemented all recommendations in the Company's most recent audit.[28]

[28] Case 18-M-0195, Proceeding on Motion of the Commission to Conduct a Comprehensive Management and Operations Audit of National Grid USA's New York Electric and Gas Utilities, Close Out Letter (filed March 20, 2023) ("March 2023 Letter").

Future management and operations audit costs have not been included in the revenue requirements for any of the Rate Years of the rate plans proposed in this Joint Proposal because the timing of the next comprehensive management and/or operations audit is unknown. If the Commission initiates a future comprehensive management and/or operations audit, then the Company will be permitted to defer the consultant costs related to such audit(s) for future recovery.

11.2.4 NPA Implementation Contractor

As discussed in Section IV.16.1.7, the Company will seek to utilize the services of an NPA Implementation contractor to assist the Company in meeting its commitments to NPAs. The revenue requirements each Rate Year includes $0.367 million of costs for the implementation contractor. If the Company's actual costs in any Rate Year exceed this amount, the Company will be permitted to defer the differences for future recovery from customers.

11.3. Additional Reconciliations, Deferrals, and True-Ups

Nothing in this Joint Proposal prevents Niagara Mohawk from petitioning for new deferrals or from implementing additional reconciliations or deferral mechanisms if approved by the Commission.[29]

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[29] To the extent a deferral is not addressed by a specific provision of this Joint Proposal or as otherwise ordered by the Commission, in determining whether a change in Niagara Mohawk's costs or revenues that falls within a provision of this Joint Proposal is incremental or decremental, Niagara Mohawk's actual cost or revenue for the year affected by the change will be compared to the corresponding annual cost or revenue item reflected in rates. The cost or revenue forecast underlying rates established in these proceedings will be as stated in this Joint Proposal or as modified by the Commission in its rate order in these proceedings, increased as appropriate for inflation and reduced to reflect the total net productivity savings assumed in rates.

12. <u>Electric and Gas Service Quality Assurance Program and Other Performance Metrics</u>

12.1. Service Quality Assurance Program

Niagara Mohawk's Service Quality Assurance Program, which includes electric and gas customer service and electric reliability performance metrics, are set forth in Appendix 14. The Signatory Parties recognize that *force majeure* events could impact the Company's performance under certain metrics. To that end, if the Company believes in any year that its inability to meet any of the established incentive targets was attributable to *force majeure* circumstances (causes that are outside its control and could not be avoided with the exercise of due cause) the Company may file a petition with the Commission requesting to avoid a negative revenue adjustment due to performance impacts that the Company can demonstrate resulted from *force majeure* impacts. All parties' rights concerning any such petition are preserved.

13. <u>Gas Safety Performance Metrics</u>

The Company's gas safety performance will be measured for each calendar year against a set of Gas Safety Performance Metrics. A total of 150 pre-tax basis points of return on common equity will be at risk per calendar year for the Company's performance under the Gas Safety Performance Metrics. Basis points at risk shall be allocated as shown in the table below and further described in the discussion of each metric in this Section.

Performance Measure	Negative Revenue Adjustment (Basis Points)	Positive Revenue Adjustment (Basis Points)
LPP Removal	15	-
Leak Management	15	6
Damage Prevention	20	10
Emergency Response Time	25	6
Gas Safety Regulations Performance Metric	75	-
Total Basis Points NRA/PRA	**150**	**22**

Any Gas Safety Performance Metrics negative revenue adjustments incurred by the Company will be deferred for future disposition by the Commission. The Gas Safety Performance Metrics will be in effect for the term of the rate plan and will continue on a year-to-year basis, unless discontinued or modified by the Commission. If the Company believes in any year that its inability to meet any of the established incentive targets was attributable to *force majeure* circumstances (causes that are outside its control and could not be avoided with the exercise of due care), the Company may petition the Commission for relief from any associated negative revenue adjustment.

13.1. Leak-Prone Pipe Removal

Niagara Mohawk will incur a negative revenue adjustment of 15 basis points should it fail to remove from service the minimum number of miles of LPP in calendar years 2025, 2026, or 2027, or the cumulative three-year total of miles of LPP by the end of calendar year 2027. Niagara Mohawk's respective targets are as follows:

	Calendar Year 2025	**Calendar Year 2026**	**Calendar Year 2027**	**Cumulative (Calendar Years 2025-2027)**
Minimum Removal Targets	33 miles	33 miles	31 miles	112 miles
Budgeted Removal Targets	38 miles	38 miles	36 miles	112 miles

The Company will continue to utilize its risk-based prioritization algorithm to identify and rank segments of LPP for removal. The Company will also continue to use leak data to prioritize LPP removals.

13.2. Leak Management

Niagara Mohawk will incur negative revenue adjustments if it fails to achieve year-end leak backlog targets for (i) workable leaks (Type 1, 2, and 2A leaks) and (ii) total leaks (Type 1, 2, 2A, and 3), as follows:

Leak Metric	**Calendar Year Targets**		**Negative Revenue Adjustment**
Workable Leaks (Type 1, 2, 2A)	Each Calendar Year	≤ 25	10 basis points
Total Leaks[30] (Type 1, 2, 2A, 3)	2025	375	5 basis points
	2026	300	
	2027	225	

The Company will be considered to have met its annual backlog targets if the target is achieved any time between December 21 and December 31 of the respective calendar year. Successful elimination of a leak does not require Type 3 leak follow-up inspections. Re-check inspections that fail will be incorporated into the Company's leak backlog.

For every 50 additional leaks repaired beyond the Total Leaks target in a calendar year, the Company will earn a positive revenue adjustment of two basis points. This incentive is capped at 150 or more additional leak repairs, *i.e.*, six basis points. In the event that the Company earns a positive revenue adjustment in a calendar year, the following year's target will be adjusted by rounding the remaining leak backlog up to the nearest 25 leak increment and setting the following calendar year's target 75 leaks below that amount. For example, if in calendar year 2025 the

[30] Total Leaks are inclusive of any high emitting leaks repaired.

Company were to have a leak backlog of 310, it would earn a PRA of two basis points. The subsequent calendar year 2026, and 2027 targets would be reset to 250, and 175, respectively.

13.3. Damage Prevention

All damages will be tracked, measured, and counted following the guidelines for the data reported for the Annual Pipeline Safety Performance Measures Report, excluding homeowners and hand damages that did not provide a one-call ticket. The Company will incur negative revenue adjustments of up to 20 basis points or positive revenue adjustments of up to ten basis points for damage prevention performance within the following targets:

NRA/PRA	Basis Points	Calendar Year 2025	Calendar Year 2026	Calendar Year 2027
NRA	20	>2.50	>2.40	>2.30
NRA	10	2.26-2.50	2.16-2.40	2.10-2.30
NRA	5	2.01-2.25	1.96-2.15	1.91-2.09
	0	1.51-2.00	1.35-1.95	1.30-1.90
PRA	5	1.25-1.50	1.25-1.34	1.20-1.29
PRA	10	<1.25	<1.25	<1.20

13.4. Emergency Response

The Company will incur a negative revenue adjustment for failure to meet the leak and odor call response targets as shown in the table below:

Required Response Time ("RRT")	Calls that must be responded to within RRT	NRA for failure to meet RRT
30 minutes	75%	12 basis points
45 minutes	90%	8 basis points
60 minutes	95%	5 basis points

Niagara Mohawk can earn a positive revenue adjustment of up to six basis points as shown in the table below.

Emergency Response Incentive	Response within 30 minutes		
Response Rate	86%-88%	>88%-90%	>90%
Positive Revenue Adjustment	2 basis points	4 basis points	6 basis points

Instances of 20 or more odor calls in a two-hour period resulting from a mass area odor issue that is not caused by the Company can be excluded from the emergency response measure provided an informational filing is filed with the Secretary of the Commission in Case 24-G-0323. All emergency reports from an event shall be included in the exclusion filing that shall: (1) be filed within 2 weeks, or 10 working days from the conclusion of such an event; (2) detail how and why the event met the prescribed exclusion criteria; (3) detail the number of emergency reports to be excluded; (4) detail the Company's response time for each of the emergency reports; and (5) detail any classified leaks, their respective Company identification numbers, and their respective dispositions, that resulted from the emergency reports. This exclusion, as well as the right to petition the Commission also applies to the 45-Minute Response Time and 60-Minute Response Time measures.

13.5. Gas Safety Regulations Performance Metric

(i) Niagara Mohawk will incur negative revenue adjustments for instances of non-compliance (occurrences of violations) of certain gas safety regulations identified during Staff's field and records audits. For Field Audits, only actions performed or required to be performed in the year that the Field Audit is conducted may constitute an occurrence under this metric. For Record Audits, only documentation required to be performed or produced during the calendar year prior to the year in which the Record Audit is conducted may constitute an occurrence under this metric unless it is a continuing violation from prior years, in which case it may constitute a non-compliance occurrence under this measure. Appendix 8 lists the high risk and other risk gas safety regulations pertaining to this metric. The Signatory Parties agreed that the Audits conducted will continue to include ten Master Operating Headquarters.

(ii) Subject to section (iii), below, Niagara Mohawk will be assessed negative revenue adjustments for each high risk and other risk violation, up to a maximum of 75 basis points per calendar year, as follows:

Audit	Type	Occurrence	Basis Points
Records	High Risk	1 to 5	0
		6 to 10	0.5
		11+	1
	Other Risk	1-10	0
		11+	0.25
Field	High Risk	1 to 10	0.5
		11+	1
	Other Risk	All	0.25

(iii) The number of occurrences of non-compliance with each high risk and other risk regulation listed in Appendix 8 subject to a negative revenue adjustment is capped at ten per audit type (Field or Records) per calendar year. If Niagara Mohawk is cited for more than ten occurrences of non-compliance with a particular high risk or other risk regulation in a calendar year, Niagara Mohawk will file with the Secretary a compliance improvement plan that contains: (i) a root cause analysis of Niagara Mohawk's compliance deficiency; and (ii) a proposed mitigation plan to address future performance. Niagara Mohawk and Staff will meet to develop a mutually agreeable mitigation plan, which will include provisions for tracking and regular reporting on Niagara Mohawk's efforts to address the compliance deficiency. The compliance improvement plan will be filed with the Secretary to the Commission within 90 days of Staff's audit letter identifying the compliance deficiency. Should the Company fail to comply with its compliance improvement plan, those violations of a code section in excess of ten that were previously capped shall count towards this metric.

(iv) At the conclusion of each audit, Staff and Niagara Mohawk will have a compliance meeting where Staff will present its findings to Niagara Mohawk. Niagara Mohawk will have ten business days from the date the audit findings are presented to cure any identified document deficiency. Only official Niagara Mohawk records, as defined in Niagara Mohawk's O&M plan, will be considered by Staff as a cure to a document deficiency. The field and record audit letters require, if applicable, that the operator respond within thirty days of the audit letter detailing what actions have and/or will be taken by the operator to remediate the non-compliances and to address Staff's concerns, and to prevent future reoccurrences. The operator's response may also include any disputes related to the noncompliance, including, but not limited to, sufficient arguments regarding the appropriateness of applying a negative revenue adjustment. The operator shall file, if applicable, its response to an audit letter in Case 24-G-0323. Staff will submit its final audit report to the Secretary to the Commission under Case 24-G-0323. If Niagara Mohawk disputes any of Staff's final audit results, Niagara Mohawk may appeal Staff's findings to the Commission. Niagara Mohawk will not incur a negative revenue adjustment on the contested findings until such time as the Commission has issued a final decision on the contested findings. Niagara Mohawk does not waive its right to seek an appeal of any Commission determination regarding a violation or penalty under applicable law.

(v) If an alleged occurrence of non-compliance with a high risk or other risk regulation is the subject of a separate penalty proceeding by the Commission, the occurrence will not count under the performance metric. Any violation of a pipeline safety regulation that has a corresponding procedural violation under 16 NYCRR §255.603(d) will count as one occurrence for purpose of calculating a negative revenue adjustment.

(vi) The total negative revenue adjustment incurred will be deferred for future use to fund gas safety and compliance improvement programs. The Company and Staff will develop mutually agreeable program scope and timelines for these safety and compliance programs, which will be submitted to the Commission for its approval in the Company's next rate case proceeding. The Company will submit regular status reports on the programs and funds expended.

13.6. Gas Safety Reporting and Exceptions

Niagara Mohawk will report its annual performance in each of the areas set forth in Sections IV.13.1 through 13.5 to the Secretary to the Commission no later than March 15 of the following calendar year.

14. Customer Programs

14.1. Energy Affordability Program

The components of Niagara Mohawk's EAP costs are shown in Appendix 5, Schedule 4 for electric and Appendix 6, Schedule 4 for gas.

In accordance with the Commission's "Order Adopting Low Income Program Modifications and Directing Utility Filings" issued and effective May 20, 2016 in Case 14-M-

0665 ("Low Income Order") the Company will adjust the energy burden and benefit levels for each calendar year to align the annual rate allowance to the two percent budget cap, if necessary and as may be modified by the Commission. The Company's EAP costs are subject to reconciliation, as set forth in Section IV.11.1.2.

14.1.1. EAP Outreach

The Company will continue its existing efforts to provide broad awareness of its EAP and other financial assistance programs to all customers in its service territory. In addition, the Company will actively seek more opportunities to conduct additional direct outreach and hold in-person events promoting the EAP and other financial assistance programs in DACs, such as, for example, HEAP, Emergency HEAP, Home & Warmth Energy Fund, Care & Share, and Hearts Fighting Hunger. Specifically, the Company commits to conduct in-person outreach events intended to reach potentially EAP-eligible customers at each of the following DACs:

36067012000	36063940001	36033940000	36089492900
36063021100	36067003400	36029940000	36093021001
36023970600	36023970900	36001012800	36075021102
36063024102	36067004200	36009961700	36001000600
36063024202	36067004301	36073401200	36029000500

Outreach events for each of the selected DACs will recur at least once annually for the duration of the rate plan term so that each DAC is provided in-person outreach at least three times. Where appropriate, the Company will seek authorization from representatives of indigenous or Native American communities before hosting an event in said communities.

The census tracts in the table above were identified in the New York State Climate Justice Working Group's Technical Documentation Appendix: Disadvantaged Communities Indicators Workbook (available at the climate.ny.gov website) as having average home energy burdens higher than 80 percent of New York State's census tracts. The above census tracts also were identified by AGREE as having estimated EAP enrollment rates of less than 25 percent of potentially eligible customers.

In addition, the Company will ensure that all of the following customers within the DACs identified in Appendix 17 receive additional, incremental direct outreach about the EAP: 1) customers whose utility service has been terminated for non-payment, but not sent to collections; and 2) customers who are eligible for field action. The Company will also ensure that the following customers within the DACs identified in Appendix 17 receive additional, incremental direct outreach to the maximum feasible extent: 1) customers who have unresolved arrears; and 2) customers with account histories and profiles indicating past (or present) difficulties paying their utility bills. "Direct outreach" shall mean one-to-one contact with potentially EAP-eligible customers through methods such as calls, emails, and texts for the purpose of assisting these customers with EAP enrollment.

The census tracts listed in Appendix 17 were identified in the New York State Climate Justice Working Group's Technical Documentation Appendix: Disadvantaged Communities Indicators Workbook (available at the climate.ny.gov website) as having average home energy burdens higher than 80 percent of New York State's census tracts. The above census tracts also were identified by AGREE as having estimated EAP enrollment rates of less than 50 percent of potentially eligible customers.

14.1.2 EAP Enrollment Targets

The Company will aim to meet an EAP Enrollment target for each of the next three Program Years. "Program years" means the year from 1) December 1, 2024 to November 30, 2025; 2) December 1, 2025 to November 30, 2026; and 3) December 1, 2026 to November 30, 2027. The EAP Enrollment target will aim to increase the average number of residential customers enrolled in EAP during each program year by 4.5 percent over the baseline. "Baseline" means the average number of residential customers enrolled in EAP during the previous program year; the baseline for Program Year 1 is the average number of residential customers enrolled in EAP from December 1, 2023 to November 30, 2024. The Company will report on its progress towards the EAP Enrollment target in its "Annual Energy Affordability Program Report." The Signatory Parties acknowledge that EAP participation levels can be influenced by many factors outside of the Company's control; therefore, in addition to describing measures the Company took to increase EAP participation, the Company's Annual Energy Affordability Program Report also will describe other circumstances that may have contributed to the level of EAP enrollment.

14.1.3. Tracking EAP Self-Certification Data

The Company will track EAP self-certification and manual enrollment data on a monthly basis. This metric will be included on the Company's monthly EAP report filed in Case 14-M-0565.

14.2. Education and Outreach to Commercial and Industrial Customers

Within six months of the Effective Date of the Joint Proposal, the Company will develop outreach and training materials for its Strategic Account Managers to educate commercial and industrial customers about the benefits and incentives associated with the clean energy solutions available through the Company's energy efficiency, demand response, electric vehicles and NPA programs (such as electrification and energy storage), including, but not limited to, information about potential tax credits for which customers may be eligible and different energy options for customers' premises.

14.3. Extreme Weather Protections

During the term of the rate plan, the Company will implement the following cold weather protections during the "Cold Weather Period" as defined in 16 NYCRR § 11.5(c)(2):

(a). Acceptance of all Home Energy Assistance Program ("HEAP") payments and suspending field collections for residential customers that receive a HEAP payment during the cold weather period, regardless of the amount due and/or the customer's payment status.

(b). Agreeing to offer a deferred payment agreement ("DPA") when a Regular and/or Emergency HEAP payment is received during the cold weather period, regardless of any previous DPA defaults.

(c). No terminations of residential service during the cold weather period on days when (i) the local forecast predicts below-freezing temperatures (32 degrees Fahrenheit) or (ii) the forecast high temperature, factoring in local forecast wind chill, will not exceed 32 degrees Fahrenheit for two or more consecutive days in the geographic operating region.

(d). No terminations of residential service to accounts identified as "elderly, blind, or disabled" ("EBD") during the cold weather period.

Further, the Company will also suspend residential electric service terminations for nonpayment during a "heat advisory" declared by the National Weather Service in any given region in the Company's service territory, when the heat index is forecasted at 95 degrees for two or more consecutive days and/or when the heat index is forecasted at 100 degrees for one or more consecutive days, subject to Commission action in, for example, Case 24-M-0586, *Proceeding on Motion of the Commission for the Establishment of Extreme Heat Protections, Practices and Procedures*.

14.4. Promotion of Special Protections

The Company will increase promotion of its special protections programs, such as Life Support Equipment, Elderly/Blind/Disabled, or Medical Equipment designations, by making information about the programs more visible on the Company's website and expanding the availability of program information at in-person events. The Company will also enhance the training of call center service representatives who have direct contact with customers who may be eligible for special procedures.

14.5. Outreach and Education Plan

The Company will file its annual outreach and education plan electronically with the Secretary to the Commission, due April 1 of each year, under Case 17-M-0475, *In the Matter of Utility Outreach and Education Plans*, using the modified template attached as Appendix 12.

14.6. Energy Efficiency Program Costs

The Company's electric and gas energy efficiency program costs will be recovered in base rates consistent with the Commission's orders issued in Case 18-M-0084.[31] The energy efficiency costs reflected in the Company's revenue requirements in Rate Year One are $112.948 million for

[31] Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative*, Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 (issued January 16, 2020) (the "NE:NY Order"); Case 18-M-0084, Order Adopting Accelerated Energy Efficiency Targets (issued December 13, 2018).

electric and $23.668 million for gas. In each of Rate Years Two and Three, the Company's revenue requirements reflect energy efficiency costs of $82.565 million for electric and $16.470 million for gas, which are the amounts included in the provisional annual budgets set forth in the Commission's July 20, 2023 Order in Case 18-M-0084.

The Company will establish a separate IEE surcharge mechanism to recover any difference between the amount of energy efficiency costs reflected in rates and any incremental energy efficiency costs approved by the Commission for the Rate Years.

The Company will implement a downward-only energy efficiency cost reconciliation mechanism. The Company will reconcile the energy efficiency costs recovered in base rates and the IEE surcharge and the Company's actual energy efficiency expenditures, and following the conclusion of Rate Year Three, the Company will defer any cumulative unspent energy efficiency funds for the benefit of customers. The reconciliation applies to the Company's aggregate total energy efficiency spending over the three-year rate period, not to individual program components. The Company will continue to be afforded the flexibility to shift funds within its respective electric and gas energy efficiency portfolios and/or to apply the deferred unspent balance to future years' energy efficiency costs, in accordance with the rules and requirements established in Case 18-M-0084.

The Signatory Parties acknowledge that future Commission action associated with the statewide EE/BE proceeding(s) may require the Company to modify aspects of its EE/BE portfolio.

An example of this reconciliation is set forth in Appendix 5, Schedule 12 for electric, and in Appendix 6, Schedule 12 for gas.

14.6.1. Energy Efficiency Full-Time Equivalents

The revenue requirements established pursuant to this Joint Proposal provide funding for the following energy efficiency-related full time equivalent ("FTE") positions:

Energy Efficiency

	Total HTY FTEs 12/31/23	Incremental FTEs RY1	Incremental FTEs RY2	Incremental FTEs RY3
NMPC	61.4	4.0	-	-

14.7. Economic Development

14.7.1. Economic Development Discount Program

The Company will continue its existing electric and gas Economic Development Discount Programs, which provide discounted electric and gas delivery rates to qualifying customers under the EJP programs, and discounted delivery rates to customers qualifying for electric discount contracts under SC-12 or to customers with existing SC-12 discount contracts. All newly certified recipients of the EJP will be required to explore energy efficiency opportunities through the Company, NYSERDA, and/or other entities. The discounts provided are subject to full reconciliation is provided in Appendix 5, Schedule 5 for electric, and in Appendix 6, Schedule 5 for gas.

14.7.2. Economic Development Grant Programs

The Company will provide the following economic development programs during the term of the rate plans:

Electric Programs:

1) Capital Investment Incentive*
2) Three-Phase Power Incentive*

3) Cooperative Business Recruitment*
4) Strategic Economic Development
5) Energy Efficiency In Empire Zones
6) Agribusiness Productivity
7) Power Quality Enhancement
8) Electric Manufacturing Productivity*
9) Renewable Energy and Economic Development
10) Brownfield Redevelopment Assistance*
11) Building Ready Upstate
12) Industrial Building Redevelopment
13) Shovel Ready Incentive
14) Clean Tech Incubation
15) Urban Center/Commercial District Revitalization
16) Mainstreet Revitalization*
17) Targeted Financial Assistance
18) 25-Cycle Investment Incentive

Gas:

1) Natural Gas Manufacturing Productivity*
2) Economic Development and the Future of Heat*
3) Sustainable Gas & Economic Development

* These programs are being provided in a modified form.

The recovery of the costs of these programs is described in Section IV.11.1.3 of this Joint Proposal.

14.7.3. Economic Development Reporting

The Company will file with the Secretary to the Commission an annual report, no later than March 31 each year, under these cases that will include a review of program activity and results for the previous calendar year, as well as results from the Company's proposed economic development grant programs for the current calendar year. For any grant applications approved for the Economic Development and Future of Heat program or the Sustainable Gas and Economic Development program, the Company will report on the greenhouse gas emissions impacts associated with the completed project and the total projected Dekatherms or MMBtu savings associated with the achieved alternatives to burning fossil fuels that were associated with the approval of the grants. The Company may propose program adjustments in its annual report. The Signatory Parties recommend that Staff may review and approve minor adjustments without further Commission review or approval. Minor program adjustments include: administrative changes such as clerical changes, contact information changes and wording updates to bring program descriptions up to date; adding customer rate classifications or industry types to eligible criteria to participate in a grant program; and increases to maximum grant funding provided that the increase in the maximum grant amount does not exceed $25,000 and increase the maximum grant amount by more than 25 percent. Commission approval will continue to be required for other program adjustments, including any proposal to: eliminate a grant program; downscale a program in either grant amounts or alter eligibility requirements; create a new grant program; or increase overall annual funding to economic development grant programs. Additionally, any change in the matching capital investment ratio, such as reducing a matching capital requirement from 4:1 to 3:1, will continue to require Commission approval. The Company will continue to meet on an annual basis with Staff and interested parties to discuss the Economic Development Program Plan.

14.8 Distributed Energy Resource Flexibility Market

During the term of the rate plan, the Company will implement a DER Flexibility Market digital platform that will enable DER operators and aggregators to more clearly understand the locations where the Company seeks grid services, the value of providing such services at those locations, and the required terms for providing that flexibility.

14.9 Building To Grid Pilot Program

During the term of the rate plan the Company will implement a Building To Grid Pilot Program to better enable owners and developers of new or recently constructed commercial developments that have on-site behind-the-meter DERs to provide localized peak demand and/or hosting capacity constraint management.

14.10 Residential Service Termination and Uncollectible Expense Incentive Mechanism (Electric and Gas)

The Company's previous termination and uncollectible incentive mechanism shall continue to be suspended for the term of the rate plan. During Rate Year Three, the Company will convene a meeting with Staff and interested stakeholders no later than October 1, 2027 to discuss potential metrics and targets for this mechanism for potential inclusion in the Company's next base rate filing.

14.11 Weatherization Health and Safety Program

During each Rate Year, the Company will provide a 100 percent shareholder-funded, with no contribution(s) from customers, weatherization health and safety ("WH&S") program capped at $1.000 million annually (*i.e.,* capped at $3.000 million over the three-year term of the rate plan). The Company will allocate any unspent funding in any given Rate Year to the following year, over and above the annual program cap as described above. Following the term of the rate plan the Company agrees to perform a reconciliation of program expenditures. The program will enable the Company to reduce health and safety barriers to customer participation in cost-saving energy efficiency programs for LMI and Disadvantaged Community households. The program will fund measures necessary to overcome barriers to participation in energy efficiency programs, including but not limited to remediation of carbon monoxide hazards, molds, lead, asbestos, pests, insufficient airing or ventilation, plumbing problems, roof and foundation repairs, blocked access to spaces in the home, and unsafe appliances. The Company will design the program in consultation with NYSERDA and with the Regional Clean Energy Hubs in the Company's service territory. The Company will permit customers participating in the program to self-attest their income for purposes of program qualification. This shareholder commitment will not extend beyond the end of Rate Year Three. No more than 60 days after the start of each Rate Year, the Company will file an annual implementation plan for the WH&S plan similar to plans that are submitted from the Company's energy efficiency programs; provided, however, that for Rate Year One, such implementation plan will be filed no more than 60 days after the issuance of a Commission order approving this Joint Proposal. At a minimum, the implementation plan will address the following:

(i) the program implementation model, including:

a. the process by which eligible customers are enrolled in the program;

b. the process by which eligible customers are selected or prioritized for participation in the program;

c. the roles and interests of the Company's employees, NYSERDA resources and Company contractors in the program;

d. eligible measures;

e. measure and customer cost caps; and

f. collaboration and coordination efforts with other energy efficiency/building electrification program administrators. Beginning in Rate Year Two, no later than 90 days after the end of the prior rate year, the Company will file an annual WH&S performance report to provide:

- spending by category (internal administration, implementation and incentives);
- the description of the measure implemented;
- the spending for each measure category as part of program spending;
- the number of customers served;
- the average cost per measure;
- the number of projects in DACs compared to the number of projects in non-DACs;
- the total number of LMI customers in the Niagara Mohawk service territory;

- lessons learned; and
- a summary of completed and ongoing collaborative efforts.

Following the submission of the report, the Company will notice and commence an annual conference to discuss program performance and any planned changes to the programs.

15. Earnings Adjustment Mechanisms

The Company will implement the EAMs in accordance with the terms and conditions set forth in Appendix 7.

16. Gas Matters

16.1. Non-Pipe Alternatives

As more fully described below, the Company will consider NPAs in the planning of proactive LPP replacements, system reinforcements, main extensions, new service line installations and service line replacements, and forecast load growth areas. The Signatory Parties agree that any such NPAs must not jeopardize the safety and reliability of the gas distribution system. Consistent with current practice, the Company will not implement any NPA without prior approval from the Commission. The Signatory Parties retain their rights to take any position they deem appropriate in response to any request for an approval of an NPA.

16.1.1. NPAs In Connection With LPP Replacement

The Company will continue to identify instances where planned LPP replacement projects could be avoided by deploying thermal energy networks or individual ground or air-source heat pumps to serve affected customers. The Company will use experience and lessons learned from pilots by utilities in New York and elsewhere to identify and address operational, billing, and customer service hurdles for purposes of informing the Company's long-term strategy for main replacement and geothermal deployment.

The Company will identify all radial segments of LPP on its system and annually target at least five segments of LPP that are not planned for replacement in the current or following construction seasons, that could be abandoned if all customers' natural gas loads were met with NPAs that would allow the section of LPP to be abandoned. This will allow time for outreach and educational efforts to customers and those communities for NPAs.

The Company will target areas of its gas distribution system that are slated for LPP replacement, that are not planned for replacement in the current or following construction seasons, where NPAs could be used to address customers' energy needs. The Company will then conduct outreach and education to affected customers and communities to determine customer interest in the NPAs. The Company will either work with its implementation contractor (discussed below) to assess the identified segments, or, if appropriate, issue requests for proposals ("RFPs") for contractors and vendors to support the potential NPA projects, including developing customer initiatives, marketing, and the provision of energy services.

The Company will enhance its existing LPP NPA program as follows:

a. LPPs that are lowest priority based on the Company's risk ranking algorithm will be prioritized for retirement and/or replacement with NPAs where feasible. The Company will prioritize the NPA opportunities that show the highest customer interest for improved success rates allowing for retirements of LPP. These approaches will not be mutually exclusive.

b. The Company will endeavor to operate the NPA program under a timeline or duration that corresponds to the LPP removal program.

16.1.2. NPAs in Connection With System Reinforcements

The Company will pursue NPAs designed to reduce gas system firm demand and avoid planned and future gas system reinforcements, including through targeted incentives for energy efficiency, demand response, and electrification.

The Company will focus and prioritize these efforts on the most constrained portions of its service areas on a forward looking basis (*i.e.*, beyond the current or following construction seasons).

These efforts will include issuing RFPs for projects and programs that could potentially avoid future system reinforcement projects. The Company will develop a community outreach methodology to focus specifically on NPAs in connection with system reinforcements three years ahead of projected traditional reinforcement project implementation.

16.1.3. NPAs in Connection With Main Extensions

For gas service requests that involve a main extension of more than 100 feet, the Company will perform a preliminary analysis of the potential to meet the needs of the prospective customers with an NPA. If this analysis shows that it is feasible and beneficial for customers from a cost perspective and would lead to reduced greenhouse gas ("GHG") emissions, the Company will contact those customers to present alternatives.

If the analysis shows that an NPA is not feasible or beneficial for customers from a cost perspective, the Company will provide justification for this finding in its annual NPA Opportunities and Programmatic Success reports (as described more fully below). The results reported will also include a list of all alternatives provided to customers. Alternatives provided to customers will include presently available electrification measures and not only traditional supply solutions.

The Company will ensure the list of presently available electrification measures alternatives provided to customers throughout its service territory is available on the Company's website and in provided materials.

16.1.4. NPAs in Connection With Service Line Installations and Replacements

The Company will develop an NPA proposal focused on new gas service line installations and existing service line replacements or relocations under the NPA Framework in place at the time of project implementation. The proposal will include a plan to conduct outreach and educate customers on the benefits of non-fossil alternatives. The Company will also consider delays in associated main replacement on facilities that are not considered high-risk as long as there are no adverse safety, operational, or financial impacts to doing so.

The Company will, no later than six months from a Commission Order adopting the Joint Proposal, convene a stakeholder engagement meeting to discuss progress related to the Company's efforts to develop NPAs focused on gas service line replacements, including (to the extent applicable) a description of which strategies have been successful, which strategies have not, and what the Company plans to modify going forward to improve program success. The Company will report on those efforts and the success of the programs in its annual NPA Opportunities and Programmatic Success reports (as described more fully below).

16.1.5. NPAs In Connection With Forecast Load Growth Areas

The Company will monitor areas on its system where load growth trends indicate future infrastructure investments will be needed to meet demand and will proactively develop load reduction strategies to avoid or mitigate the need for investment in gas infrastructure in these areas. The Company will report on those efforts and the success of the programs in its annual NPA Opportunities and Programmatic Success reports (as described more fully below).

16.1.6. Integrated Energy Planning ("IEP") Pilot To Support LPP NPAs

The Company will implement, in accordance with the established NPA process, an IEP pilot to support targeted customer electrification for NPAs to avoid LPP replacement for portions of the distribution system and infrastructure that may need to be updated, repaired, and/or replaced in the next four to seven years.

The main objectives of the pilot will be to:

1. Define and test joint gas and electric IEP processes and engineering analysis methodologies to support NPAs;

2. Develop and test a joint gas and electric cost recovery framework for NPAs to account for customer equipment replacements, potential gas system retirements, and electric system upgrades in tandem;

3. Test joint gas and electric approaches to customer engagement to identify avenues to increase customer willingness to participate in coordinated gas to electric conversions; and

4. Identify barriers to customer adoption and partner with local communities to test new outreach approaches to mitigate barriers.

The Company has identified nine LPP segments in the East Gate region that require minimal electric system upgrades to electrify with a total of 150 customers, that will be pursued for the pilot. These segments fall within three towns in the Capital District, two of which are DACs.

As part of the pilot, the Company will investigate offering the following incentives to customers during outreach:

- A free home energy assessment prior to making the decision to participate;
- Coverage of 100 percent of the cost to replace gas equipment with electric alternatives;
- Coverage of 100 percent of the cost to weatherize the building envelope to the levels necessary to ensure effective sizing and efficiency of electric heating equipment (including health and safety measures necessary for weatherization such as removal of asbestos); and
- An NPA Heat Pump Monthly Credit (as discussed below) to help offset increases in electricity bills.

Within three months of the Commission's Order approving this Joint Proposal, the Company will begin community engagement and customer outreach for the pilot locations. Cost recovery for the building weatherization and electrification incentives, potential electric system upgrades, and potential gas system retirements will be pursued in a future "IEP Pilot Deployment filing" made in Rate Year Two, once outreach is complete, for the segments where customers opt-in to move forward with the equipment conversions. Once approved, the Company will plan to implement the building and utility system replacements in Rate Year Three. The Company will also submit a Pilot Evaluation Report in Rate Year Three outlining the results of the pilot, lessons learned, and recommendations to inform integrated energy planning processes, future electrification efforts, and to further our NPA commitments.

Pilot program costs will be allocated to and recovered from participating rate classes only.

16.1.7. NPA Customer Outreach

During the term of the rate plan, the Company will increase its efforts to inform customers and communities of NPA project opportunities and increase customer education and outreach in the following manner:

(i) The Company will ensure that upcoming NPA project opportunities throughout the service territory are available on the Company's website and in promotional materials in a timely fashion;

(ii) Each NPA program component will include an outreach methodology for both building and non-building owners;

(iii) The Company will use internal resources and an implementation contractor to inform customers and communities that could participate in NPA opportunities;

   i. by email;
   ii. by phone;
   iii. by bill insert or other marketing material;
   iv. at local/public events; and
   v. through in-person engagement by knocking on doors.

(iv) For each NPA opportunity, the Company will make note of the effectiveness of customer outreach efforts, customer feedback, and disposition of gas alternatives as part of participation in an NPA project (*e.g.*, what incentives are persuasive or not persuasive, why customers are willing or unwilling to eliminate their gas service, etc.); and

(v) The Company will report on these efforts and the success of the program in their annual NPA Opportunities and Programmatic Success reports (as described more fully below), and the Company will identify the types of stakeholders (*e.g.*, governmental entities, developers, community groups, etc.) included in the Company's outreach and marketing as part of its reporting.

The Company will seek to utilize the services of an NPA implementation contractor with the necessary planning, engineering, and marketing expertise needed to execute the Company's commitments to NPAs. If the amount required to implement NPAs in line with these commitments exceeds the amount embedded in the revenue requirement (which is $0.367 million per year), the Company will be permitted to defer its additional costs for future recovery.

16.1.8. Miscellaneous NPA Provisions

16.1.8.1 Behind the Meter Upgrades

NPAs may include costs associated with behind-the-meter upgrades and health and safety measures necessary to facilitate participation.

16.1.8.2 Impact of NPAs On Bill Affordability

The Company will consider and quantify the impacts of an NPA on bill affordability for customers targeted by any NPA that includes customer electrification. Specifically, the Company will identify the number of EAP participants expected and provide a plan for mitigated energy burden increases with respect to any NPA that include electrification.

16.1.9. NPA Reporting

Beginning in Rate Year Two, the Company will file an annual report with the Commission no later than July 31 setting forth in detail NPA Opportunities and Programmatic Success. The Company will report on its efforts to pursue NPAs in connection with LPP replacement, system reinforcements, service line installations and replacements, and customer connections. The

Company will report on its retention of an implementation contractor, describing how the contractor has affected the Company's efforts, and the costs associated with retaining the contractor, which shall be deferred if above the amount included in rates.

In the annual report, the Company will identify and provide justification, including, but not limited to, supporting documentation, for all instances in which the Company provided analyses that concluded that an NPA was not feasible or beneficial for customers from a cost perspective or would not lead to reduced GHG emissions, or that could not elicit sufficient customer participation. The Company will also identify prioritized portions of its service areas due to system constraints. The results will also include a list of all alternatives recommended to customers and will include all available electrification measures and other non-fossil alternatives. The reports will also contain examples of marketing materials.

To the extent a similar report is required by the Commission in the Gas Planning Proceeding, the Company's obligation to provide information in the NPA Opportunities and Programmatic Success report will be limited to information that is not required by the Gas Planning Proceeding reporting requirements.

16.2. NPA Heat Pump Monthly Credit

Beginning in Rate Year One, the Company will implement a new electrification incentive mechanism for customers who purchase both gas and electric services from the Company and are offered an NPA. The incentive will provide a credit that will be available to residential and small commercial non-demand customers that install a heat pump as part of an NPA. The credit will be determined by dividing the estimated incremental load from the heat pump by twelve and then multiplying the quotient by the base delivery $/kWh charge (excluding surcharges) to develop a fixed monthly bill credit amount. Qualifying customers will receive the monthly credit for a term of five years, however, in the event the qualifying customer moves or closes the account at the premise where NPA Project equipment has been installed, the term will end following the last billing period of the customer at that premise. The costs of the program will be recovered through the RDM from the classes of customers participating in the program. The number of customers receiving the credit will be included in the annual NPA report.

16.3. Gas Marketing

The Company will not market new gas connections and conversions, including any rebates for heating-oil-to-gas conversions or new gas customers, during the term of the rate plan. The Company will encourage applicants requesting new or expanded gas service to consider electrification options, and the Company will require new gas customers to acknowledge in writing that they have been provided information on electrification alternatives.

Nothing contained herein will preclude the Company from marketing its approved energy efficiency programs; nor will anything herein prevent the Company from providing information to current or prospective customers concerning their rights to purchase service from the Company. In the marketing of energy efficiency programs to customers the Company will encourage customers to explore electrification where possible given the nature of the program (*e.g.*, full equipment replacements). The Company's direct energy efficiency marketing will not include language referring to gas as clean or having environmental benefits.

16.4. RNG Pricing

If the Company purchases RNG from a facility connected to its distribution system, the prices paid for such supplies should be consistent with the market price of natural gas supplies purchased at similar locations and consistent with the Company's existing gas supply portfolio. The prices paid should be no greater than the prices of other gas supplies purchased at the Company's city gates. The Company will provide details of annual RNG purchases as part of the annual gas reconciliation process.

16.5. Gas Customer Choice Matters

16.5.1 Daily Balanced Customers – Primary Point Capacity

The Company provides firm, non-core transportation service to large commercial and industrial customers that are subject to daily balancing and are referred to as Daily Balanced Customers. The majority of Daily Balanced Customers, or the Marketers that provide their gas supply, have contracted with upstream interstate natural gas pipelines that interconnect with the Company's gas distribution system[32] for firm natural gas transportation capacity that provides primary delivery point capacity ("PPC") to the Company's city gate delivery points in an amount sufficient to serve the customer's Maximum Peak Day Quantities ("MPDQ"). The MPDQ represents the Company's forecast of the maximum quantities of natural gas that a customer will consume on a "design day"[33] which is the coldest day that Company plans and designs its gas distribution system to serve. Certain Marketers/Direct Customers have not contracted for PPC to serve daily balanced firm loads, but rely on secondary firm capacity that has a lower curtailment priority on the interstate pipeline system.

[32] The interstate pipelines that interconnect with the Company's distribution system are (1) Eastern Gas Transmission System ("EGTS") (formerly known as Dominion Transmission, Inc.) and Tennessee Gas Pipe Line ("Tennessee") at the Company's East Gate, and (2) EGTS, Iroquois Gas Transmission System ("IGTS") and Empire Pipeline ("Empire") at the Company's West Gate.

[33] The Company's current Design Day, as filed with the Commission, is based on a day in which the forecast average temperature in the Company's service territory is minus 10° Fahrenheit.

While the interstate pipelines that interconnect with the Company's distribution system have a limited amount of PPC capacity available for sale at the Company's city gates, the quantity of PPC available is not sufficient to serve the forecast MPDQs of the Company's existing Daily Balanced Customers. In recognition of this situation, the Signatory Parties agree as follows:

(i) Marketers/Direct Customers must maintain current levels of PPC for Existing Daily Balanced Customers.

(ii) Marketer/Direct Customers must participate in the annual verification of PPC by the Company.

(iii) For the Existing Daily Balanced Customers not being served by PPC ("Non-PPC Daily Balanced Customers"), Marketers/Direct Customer must submit Pool Curtailment Plans (by September each year and as needed throughout the year) on the Company's Electronic Bulletin Board website. Each October, both the Company and the applicable Marketer will provide notice to customers on the curtailment list that they may be curtailed. Marketers/Direct Customer will be required to notify the Company by September 15 of each year of the identified customers and respective contact information. The Company will work with Marketers/Direct Customers to develop a notification form that is mutually agreeable by August 1, 2025.

(iv) If PPC becomes available at the East Gate or West Gate and the Company's distribution system has the takeaway capacity to utilize the PPC, then the Company will notify Marketers/Direct Customers who lack sufficient PPC of its availability by September 1 of each year. Marketers/Direct Customers may either elect to contract for such PPC to reduce their existing PPC shortfall as of November 1, or if they fail to do so by the last week of October, the Company will contract for the capacity and release it to Marketers/Direct Customers who are deficient on a basis proportionate to their existing PPC shortfall at the affected location -- East Gate or West Gate, as applicable -- as of November 1 of each year. Capacity will be released for a one-year period each year ahead of the winter heating season at the rates paid by the Company. These procedures will be in place by September 2025.

(v) Establishment of an Adjusted MPDQ:

- Prior to September 1 of each winter season, Marketers/Direct Customers will have the opportunity to provide the Company with an annual Adjusted MPDQ for Customer(s) in the Marketer's pool.
- The Adjusted MPDQ will only be considered; (1) in the Company's annual PPC verification, and (2) when a Daily Balanced Pool Alert (as described below) is in effect and Customer(s) usage must be limited to the Adjusted MPDQ.
- The Adjusted MPDQ will be in effect for a one-year period and must be confirmed contractually with the Company by both the Marketer and the Customer prior to September 1 of each year. If Customer switches Marketer pools during the annual period, the Adjusted MPDQ will follow the Customer in the instance of a Daily Balanced Pool Alert.

- If Customer exceeds the Adjusted MPDQ during a Daily Balanced Pool Alert then the Customer will be penalized for unauthorized usage in an amount equal to $50 per dekatherm ("dth") plus the Incremental Cost of Gas ("ICOG") for usage in excess of Adjusted MPDQ plus any authorized imbalance tolerance.

(vi) Where an Existing Non-PPC Daily Balanced Customer (1) transfers all or substantially all of its facilities (*i.e.*, personal property and real property rights) at a delivery point on the Company's distribution system to another entity that is expected to utilize gas service in the same manner, and (2) those facilities continue to operate at the same delivery point, at the same forecast MPDQ, then the acquiring entity will be considered a Replacement Non-PPC Daily Balanced Customer and shall be treated as an Existing Daily Balanced Customer and that Customer will be included in the Customer's Marketer's Pool Curtailment Plan.

(vii) New Daily Balanced Customers:

- Additional PPC must be secured for all New Daily Balanced Customers that are not considered Replacement Non-PPC Daily Balanced Customers. This obligation shall apply only to the MPDQ or the Adjusted MPDQ of the capacity required to serve the New Daily Balanced Customer. This obligation shall not increase the amount of PPC required for Marketers to serve any other customers.

(viii) A Marketer/Direct Customer may demonstrate PPC to the Company's city gate delivery point or points by entering into a contract that provides firm PPC during at least the five (5) winter months (November – March) as long as its PPC contract has a Right of First Refusal ("ROFR").

(ix) The Company will file an annual report with the Commission in the established annual winter supply review proceeding, detailing peak day PPC deficiencies of the Daily Balanced customer classes by September 15th each year. The report will also detail capacity requirements for the pilot Partially Interruptible service class described in Section IV.4.8 of this Joint Proposal and a quantification of the peak day demand reduction from both customers that purchase either interruptible service under SC-6 or as part of the pilot Partially Interruptible service class.

The Company will modify its GTOP and the Tariff, as applicable, to include and conform to these rules.

16.5.2 Daily Balanced Pool Alert

Daily Balanced Pool Alerts may be issued by the Company to Daily Balanced Customers only when a Company-issued Operational Flow Order ("OFO") is in place to address (1) gas supply conditions on a day when the average temperature in the Company's service territory is forecast to be at or below the design day temperature that the Company files with the Commission; or (2) other equivalent emergency conditions where the Company can demonstrate that a Marketer/Direct Customer shortfall in deliveries of gas will result in a threat to the operational reliability of the Company's system.

During an OFO, if the Company determines that a Marketer/Direct Customer does not have enough gas scheduled/confirmed to meet the MPDQs (or Adjusted MPDQs) of the Direct Customer or the Marketer's pool of customers, the Company may issue a Daily Balanced Pool Alert to the Marketer/Direct Customer. After the Company has issued a Daily Balanced Pool Alert, the Company will compare the Marketer's/Direct Customer's total confirmed nominations, including any D-1 nominations, to the Marketer's/Direct Customer's MPDQ (or Adjusted MPDQ) at East Gate or West Gate as applicable. If the total confirmed nominations are inadequate to meet the MPDQ or Adjusted MPDQ of the Direct Customer or the Marketer's pool of customers within the applicable balancing tolerance bands, the Company may direct the Direct Customer/Marketer to curtail natural gas usage in accordance with that Marketer's Pool Curtailment Plan, but only to the extent reasonably required to ensure continued reliable operation of the Company's gas delivery system.

Specific Daily Balanced Pool Alert curtailment criteria that the Company shall follow are:

- The Company will only curtail if it is determined by the Company that the Marketer's/Direct Customer's shortfall will materially contribute to a threat to the operational reliability of the Company's system.
- Curtailments will be dictated by the rankings provided by the Marketer on its Marketer Pool Curtailment Plan and shall be based on pool area (i.e., East Gate or West Gate).
- The number of customers curtailed shall be limited to only those needed to address the Marketer's shortfall.
- Marketer Pool Curtailment Plans shall not be used by the Company for any purpose other than curtailments implemented under its Daily Balanced Pool Alert. All other

curtailments shall be governed instead by the relevant existing provisions of the Company's Tariff.

- The Company shall notify the Director of the Energy System Planning and Performance or its successor of the New York State Department of Public Service when a Direct Customer or Marketer's customer(s) are curtailed during a Daily Balanced Pool Alert and the reason for the curtailment.
- The Company will amend its Tariff and Gas Transportation Operating Procedures Manual, as appropriate, to include the following terms relevant to the issues of Daily Balanced Pool Alerts and more fully set forth in Appendix 16:
    - Procedures to notify Non-PPC Daily Balanced Customers to stop consuming gas;
    - Financial penalties starting at $50/dt for non-compliant Customers;
    - Failure to comply procedures for non-compliant Customers, including escalating penalties;
    - A list of further consequences for repeated non-compliance, including potential metering changes;
    - Curtailment planning processes and procedures to be incorporated in the Company's gas forecasting for week-ahead and day-ahead processes; and
    - Procedures for shutting off customers that do not comply with curtailment orders if the Company deems it necessary to physically curtail gas usage.

The Company will modify its GTOP and the Tariff, as applicable, to include and conform to these rules.

16.5.3 Daily Imbalance Cash-Out Changes

The Company will amend its tariff to modify the East Gate and West Gate cashout mechanisms that are used to resolve imbalances as follows:

The East Gate cashout mechanism will be modified to include prices of gas purchased on the Tennessee pipeline system in the winter and the West Gate cashout mechanism will be modified to include prices of gas purchased on the IGTS pipeline system in the winter. The Company will implement a winter (November – April) and a summer (May – October) cashout for each Gate.

EAST GATE:

Winter: Daily Average of EGTS South Point ("SP")[34] + EGTS North Point ("NP") + Tennessee Zone 6 prices

Summer: Daily Average of EGTS SP + EGTS NP (remains unchanged from current cashout mechanism)

WEST GATE:

Winter: Daily Average of EGTS SP + EGTS NP + IGTS receipts

Summer: Daily Average of EGTS SP + EGTS NP (remains unchanged from current cashout mechanism)

These changes will be implemented in the Company's new Customer Choice IT system ("GTIS 2.0") which is planned to be placed in service in Summer 2026. The new cashouts will take effect in November 2026 following implementation of GTIS 2.0.

[34] EGTS SP and NP are virtual pooling points where gas may be bought and sold on the EGTS pipeline system.

The Company will modify its GTOP and the Tariff, as applicable, to include and conform to these rules.

16.5.4 D-1 Nominations

16.5.4.1 D-1 Penalty Provisions

The Company provides certain non-core, firm Daily Balanced Customers with the ability to make D-1 elections that require the Company to purchase gas supplies to serve a portion of the Customer's anticipated usage on particular days. To exercise D-1 rights the Customer with D-1 rights or its authorized agent ("Customer's Marketer") must place a pipeline nomination with the Company, not to exceed its D-1 Election, in order to purchase Standby Sales Service gas supplies. Nominations are due by 8:00 a.m. on the business day before the day the gas will be consumed. For example, for a Gas Day commencing at 10:00 a.m. on Thursday, nominations are due by 8:00 a.m. on Wednesday, the prior day.

Both D-1 elections and nominations are submitted at the Customer level and for violation enforcement purposes, are not pooled at the Marketer level. The Company will monitor D-1 daily nominations at the Customer level and compare them to the individual Customer usage each gas day. The Company will apply a plus five percent tolerance level consistent with the daily cashout tolerance. The Company will assess violations to Marketers for any Customer whose D-1 nomination is greater than the Customer's usage outside the plus five percent tolerance (*i.e.*, nomination is greater than 105 percent of customer's usage).

The Company will bill marketers for the D-1 nomination in excess of the cashout tolerance at the ICOG rate plus $5 per dth, at the customer level, if out of tolerance. For example, if Marketer A has ten D-1 customers and four customers are in violation, Marketer A will be billed at the standard daily Weighted Average Cost of Gas ("WACOG") rate for the six Customers without violation, and for the Customers that violate the Company's rule, the nomination in excess of the tolerance for those Customers will be billed at the daily ICOG rate plus $5 per dth instead of the standard daily WACOG.

The Company will modify its GTOP and the Tariff, as applicable, to include and conform to these D-1 nomination rules and penalties.

16.5.4.2 Replacement D-1 Customer

Where an Existing D-1 Customer (1) transfers all or substantially all of its facilities (*i.e.*, personal property and real property rights) at a delivery point to another entity that is expected to utilize gas service in the same manner, and (2) those facilities continue to operate at the same delivery point and at the same forecast MPDQ, then the acquiring entity will be considered a Replacement D-1 Customer and may continue to receive the Existing D-1 Customer's D-1 Election at the same delivery point. There will be no new D-1 Elections granted to new customers, and Existing D-1 Customers may not transfer any portion of their D-1 Election to another customer.

The Company will modify its GTOP and the Tariff, as applicable, to include and conform to these rules.

Consistent with this provision, beginning on the date of a Commission Order adopting this Joint Proposal, Fedrigoni Special Papers will be considered a Replacement D-1 Customer with a D-1 election of no more than 700 dth per day at its existing facility located in Waterford, New York, which receives gas service under an SC-8 account. To ensure clarity, Fedrigoni Special Papers agrees and relinquishes any claim to a D-1 election it may have as a Replacement D-1 Customer based on its predecessor's facilities located in Cohoes, New York.

16.6 SC-5 and SC-7 Human Needs Customers

Human needs customers taking service under service classifications SC-5 and SC-7 will require a contract that provides firm PPP during at least the five winter months (November-March) as long as the PPC contract has a ROFR. Marketer/Direct Customers must participate in the annual verification of PPC by the Company.

The Company will modify its GTOP and the Tariff, as applicable, to include and conform to these rules.

17. CLCPA and Other Future of Heat Matters

17.1 CLCPA and DAC Report

The Company will file an annual report (the "CLCPA and DAC Report") with the Commission within 120 days of the end of each Rate Year in this Case and in Matter - 23-02017, In the Matter of Reporting Investments and Benefits to Disadvantaged Communities. Each CLCPA and DAC Report will include a narrative description of the data reported on, including how the Company tracks and collects the data, any assumptions relied on in the report and, for energy efficiency programs marketed by the Company, descriptions of the Company's efforts to reach DACs and low-income customers, including program implementation and outreach strategies targeted toward such populations. For purposes of the annual CLCPA and DAC Report, the Company will use the Department of Environmental Conservation disadvantaged community maps in effect for the Rate Year that is the subject of the report.

To the extent possible, the CLCPA and DAC Report will incorporate performance data and other information in the Company's existing reporting on energy efficiency, demand response, capital investments, and other relevant areas, with the understanding that the timing for already established reporting requirements may not coincide with the timing of the CLCPA and DAC Report. Performance data will be tracked and reported in a manner generally consistent with the Company's current practices in each area (e.g., fiscal year vs. calendar year reporting, units in which energy savings are reported).

This report is to be incremental to other reporting requirements established by the Commission in other proceedings and/or Staff Guidance documents. Future Commission actions and/or Staff guidance may expand and/or modify the CLCPA reporting requirements set forth below. To the extent the report identifies instances where the Company is not achieving targets, or instances where a program is not meeting goals regarding the level of benefits targeted for DACs, the Company will include an action plan for improving performance in those areas. Within 60 days of filing the CLCPA and DAC Report, the Company will convene a meeting with interested stakeholders to discuss and provide feedback on the report and the Company's activities as discussed therein. Additional details concerning the CLCPA and DAC Report are set forth in Appendix 11.

17.2 Utility Thermal Energy Network Proceeding

During the term of these rate plans, the Company will continue to participate in the Case 22-M-0429 and will implement, as authorized by the Commission, natural geothermal energy systems.

18. <u>Filing for New Rates</u>

18.1. During the Term of the Rate Plan

The Company agrees not to file for new base delivery rates prior to April 1, 2027. The following exceptions will apply:

(a) The Company may petition the Commission to implement changes to its base rates as may be required or warranted by newly-enacted legislation or regulations and nothing in the Joint Proposal shall prohibit Niagara Mohawk from implementing changes to rates or charges, in a manner to be determined by the Commission, as may be required by newly enacted legislation or regulations;

(b) The Company may petition the Commission for deferral of extraordinary expenses or other costs;

(c) The Company may petition the Commission for approval of new services and/or discrete incentives;

(d) The Company may petition the Commission for changes to rate design or revenue allocation that are revenue neutral, including, but not limited to, the implementation of new service classifications and/or elimination of existing service classifications. Such petitions must demonstrate that the proposed changes are consistent with the overall rate designs and revenue allocations provided for in this Joint Proposal;

(e) The Company may petition the Commission for minor changes in base rates, provided the effect is *de minimis* or is essentially offset by associated changes in other base rates, statements, terms, or conditions of service; and

(f) The Company may file tariff amendments to implement changes as described in this Joint Proposal.

Any party may take any position on any filing made by the Company pursuant to this Section. Moreover, any party may petition the Commission for minor changes in base rates, provided the effect is *de minimis* or is essentially offset by associated changes in other base rates, statements, terms, or conditions of service. Notwithstanding the foregoing, nothing in the Joint Proposal shall prohibit the Commission (upon its own motion or upon motion of an interested party) from exercising its ongoing statutory authority to act on the level of the Company's rates in the event of unforeseen circumstances that, in the Commission's judgment, have such a substantial impact on the rate of return as to render the return on common equity devoted to either the Company's gas or electric operations, unreasonable, unnecessary, or inadequate for the provision of safe and adequate service.

19. Corporate Structure and Affiliate Rules

The corporate structure and affiliate rules that apply to the Company are set forth in Appendix 15.

20. Other Provisions

20.1. Submission to the Commission

The Signatory Parties will request that the Commission adopt the terms of this Joint Proposal without modification. The Signatory Parties intend that the terms of this Joint Proposal will be adopted by the Commission expeditiously to moderate rate compression to the extent possible and as being in the public interest and agree individually to advocate its adoption by the Commission in its entirety and to act so as to expedite that result.

20.2. Conditioned on Commission Adoption/No Severability

The Signatory Parties intend this Joint Proposal to be a complete resolution of all issues in these proceedings. It is understood that each provision of this Joint Proposal is in consideration and support of all the other provisions, and expressly conditioned upon acceptance by the Commission. Except as set forth herein, none of the Signatory Parties is deemed to have approved, agreed to, or consented to any principle, methodology, or interpretation of law underlying or supposed to underlie any provision herein. If the Commission does not adopt this Joint Proposal according to its terms, then the Signatory Parties to the Joint Proposal will be free to pursue their respective positions in this proceeding without prejudice.

20.3. Application of Agreement/No Precedent

Except as otherwise stated in this Joint Proposal, the provisions of the Joint Proposal apply solely to and are binding only in the context of this Joint Proposal and this proceeding. None of the terms of this Joint Proposal and none of the positions taken by any Signatory Party with respect to this Joint Proposal may be referred to, cited by, or relied upon by anyone in any manner as precedent or otherwise in any other proceeding before the Commission or any other regulatory body or before any court of law for any purpose other than the adoption, implementation, furtherance, or extension of this Joint Proposal. Concessions made by any Signatory Party on any issue do not preclude that party from addressing such issues in future rate proceedings or in other proceedings.

20.4. Future Actions/Dispute Resolution

The Signatory Parties recognize that certain provisions of this Joint Proposal contemplate actions to be taken in the future and agree to cooperate with each other in good faith in taking such actions.

In the event of any disagreement over the interpretation of this Joint Proposal that cannot be resolved informally among the Signatory Parties, the party claiming a dispute will serve a Notice of Dispute on the remaining parties, briefly identifying the provision or provisions of this Joint Proposal under dispute and the nature of the dispute, and convening a conference in a good faith attempt to resolve the dispute. If any such efforts are not successful in resolving the dispute among the Signatory Parties, the matter can be submitted to the Commission for resolution.

20.5. Continuation

Except as set forth in this Joint Proposal, following the expiration of the term of the rate plan, all provisions of this Joint Proposal will continue until changed by order of the Commission. Except as expressly provided otherwise, any targets, goals, deferral thresholds, or other similar items set forth in this Joint Proposal for Rate Year Three will continue beyond Rate Year Three until modified by the Commission. Notwithstanding the foregoing, the following provisions of this Joint Proposal will terminate at the expiration of the term of the rate plan without further order from the Commission:

(i) the downward-only tracking mechanism for IT, electric and gas net utility plant and depreciation expense described in Sections IV 11.1.11,11.1.17, and 11.1.20.

20.6. Extension

Nothing in this Joint Proposal will be construed as precluding the active parties from convening additional conferences and from reaching agreement to extend this Joint Proposal on mutually acceptable terms and from presenting an agreement concerning such extension to the Commission for its consideration.

20.7. Entire Agreement

This Joint Proposal sets forth the entire agreement of the Signatory Parties and supersedes any prior or contemporaneous written documents or oral understandings among the Signatory Parties concerning the matters addressed herein. In the event of any conflict between this Joint

Proposal and any other document addressing the same subject matter, this Joint Proposal will control.

20.8. Counterparts

This Joint Proposal is being executed in counterpart originals and will be binding on each Signatory Party when the counterparts have been executed.

[Signature Pages Follow]

Niagara Mohawk Power Corporation d/b/a National Grid has this day signed and executed this Joint Proposal.

By: Kristoffer P. Kiefer
Kristoffer P. Kiefer, Esq.
Assistant General Counsel and Director, NY Regulatory

Date: April 18 , 2025

The New York State Department of Public Service Staff has this day signed and executed this Joint Proposal.

By: ______________________________

Jessica R. Vigars, Esq.
Department of Public Service,
Staff Counsel

Date: April 24, 2025

Multiple Intervenors has this day signed and executed this Joint Proposal.

By: S. Jay Goodman

S. Jay Goodman, Esq.
Couch White, LLP
Counsel for Multiple Intervenors

Date: April 17, 2025

Walmart, Inc. has this day signed and executed this Joint Proposal.

By: ______________________________

Steven Lee, Esq.,
Spilman, Thomas & Battle, PLLC
Counsel for Walmart, Inc.

Date: April 18, 2025

New York Solar Energy Industries Association has this day signed and executed this Joint Proposal.

DocuSigned by:

Noah Ginsburg

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By: ______________________________

Noah Ginsburg,
Executive Director

Date: April 17, 2025

Independent Power Producers of New York, Inc. ("IPPNY") has this day signed and executed this Joint Proposal, limited to the terms regarding electric service. IPPNY takes no position with respect to the terms regarding gas service.

By: ______________________

Gavin J. Donohue,
President and Chief Executive Officer

Date: April 17, 2025

The United States Department of Defense and all other Federal Executive Agencies has this day signed and executed this Joint Proposal.

By: John Joseph McNutt

John Joseph McNutt, Esq.
U.S. Army Legal Services Agency,
As authorized agent for the United States Department of Defense and all other Federal Executive Agencies

Date: April 16, 2025

Turning Stone Enterprises, LLC has this day signed and executed this Joint Proposal.

By: ______________________________

Meghan M. Beakman, Esq.,
General Counsel and Senior Vice President for Administration

Date: April 17, 2025

Fedrigoni Special Papers North America, Inc. has this day signed and executed this Joint Proposal.

By: ______________________________
Jeffrey D. Kuhn, Esq.
Harris Beach Murtha Cullina PLLC
Counsel for Fedrigoni Special Papers North America, Inc.

Date: April 16, 2025

Alliance for a Green Economy has this day signed and executed this Joint Proposal.

By: Jessica Azulay
Jessica Azulay
Executive Director

Date: April 17, 2025

Empire Natural Gas Corporation has this day signed and executed this Joint Proposal.

By: ______________________
Seth Barrows
President

Date: April 16, 2025

New York Geothermal Energy Organization has this day signed and executed this Joint Proposal.

By: /s/ *John Rath*
John Rath,
Director of Operations

Date: April 16, 2025

New Yorkers for Clean Power has this day signed and executed this Joint Proposal.

By: Anshul Gupta
Anshul Gupta
Policy and Research Director

Date: April _17__, 2025

International Brotherhood of Electrical Workers, Local Union 97 has this day signed and executed this Joint Proposal.

By: Michael Shelby
Michael Shelby, President
International Brotherhood of Electrical Workers, Local Union 97

Date: April 14, 2025

The New York Power Authority has this day signed and executed this Joint Proposal in support of Section IV, Subsections 6.1.1, 6.8 and 6.9 only, and it takes no position with respect to any of the other provisions in the Joint Proposal.

By: Maribel Cruz-Brown
Maribel Cruz-Brown,
Senior Vice President, Customer Solutions

Date: April 16, 2025