Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Direct Testimony

of

Climate Leadership and Community Protection Act Panel

Dated: May 2024

Testimony of Climate Leadership and Community Protection Act Panel

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I. Introduction and Qualifications

Q. Please introduce the members of the Climate Leadership and Community Protection Act ("CLCPA") Panel ("Panel").

A. The Panel consists of Karsten A. Barde, Patricia J. Dorsch, Meghan McGuinness, and Gideon Banner.

Q. Mr. Barde, please state your name and business address.

A. My name is Karsten A. Barde. My business address is 170 Data Drive, Waltham, Massachusetts 02451.

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

A. I am employed by National Grid USA Service Company, Inc. ("National Grid Service Company" or "Service Company"), a subsidiary of National Grid USA ("National Grid"), as a Director on the U.S. Policy and Regulatory Strategy team. In that role, I provide services to Niagara Mohawk Power Corporation d/b/a National Grid ("Niagara Mohawk" or the "Company"). My primary responsibilities include analyzing public policy and advising National Grid's operating companies on the immediate and potential future impacts of public policy, with a particular focus on clean energy transition issues. I also support the Company in

determining its positions on public policy topics and engaging with stakeholders in emerging areas of interest.

Q. Please describe your educational background and business experience.

A. I have a Bachelor of Arts from Dartmouth College in Government and Geography and a Master of Business Administration with a focus on Strategy and Sustainability from the Tuck School at Dartmouth. I have worked at National Grid for ten years in a variety of roles, including new product development, customer strategy, and regulatory strategy. I previously worked at Pacific Gas & Electric in San Francisco, and at a social venture fund in Boston.

Q. Have you previously testified before the New York Public Service Commission ("Commission")?

A. Yes. I submitted testimony on behalf of The Brooklyn Union Gas Company d/b/a/ National Grid NY ("KEDNY") and KeySpan Gas East Corporation d/b/a National Grid ("KEDLI") in Cases 23-G-0225 and 23-G-0226 (the "2023 KEDNY and KEDLI Rate Cases").

Q. Ms. Dorsch, please state your name and business address.

A. My name is Patricia J. Dorsch. My business address is 1650 Islip Ave, Brentwood, New York 11717.

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

A. I am employed by the Service Company as Director of New York Environmental Sustainability. My primary responsibilities include working with National Grid's New York operating companies, including Niagara Mohawk, to support National Grid's net-zero ambitions and oversee emissions calculations and external disclosures.

Q. Please describe your educational background and business experience.

A. I have a Bachelor of Engineering in Mechanical Engineering from Stony Brook University and a Master of Science in Management Engineering from Long Island University. I have worked for National Grid for 38 years with experience in load research, gas sales, technical support for energy efficiency, customer renewables including solar and small wind, and sustainability.

Q. Have you previously testified before the Commission?

A. Yes. I submitted testimony on behalf of KEDNY and KEDLI in the 2023 KEDNY and KEDLI Rate Cases.

Q. Ms. McGuinness, please state your name and business address.

A. My name is Meghan McGuinness. My business address is 170 Data Drive, Waltham, Massachusetts 02451.

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

A. I am employed by the Service Company as Director of U.S. Regulatory Strategy. My primary responsibilities include development of regulatory and policy strategy related to clean energy, climate policy, and innovative regulatory frameworks.

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Arts in Economics and Environmental Studies from Middlebury College and a Master of Science in Technology and Policy from Massachusetts Institute of Technology ("MIT"). Prior to joining National Grid in 2016, I worked on energy and environmental policy and regulatory issues affecting utilities for a number of

organizations, including the Bipartisan Policy Center, NERA Economic Consulting, MIT's Center for Energy and Environmental Policy Research, the U.S. Environmental Protection Agency ("EPA"), and Resources for the Future. At National Grid, I was a Principal Analyst prior to being promoted to my current role in January 2022.

Q. Have you previously testified before the Commission?

A. Yes. I submitted testimony on behalf of KEDNY and KEDLI in the 2023 KEDNY and KEDLI Rate Cases.

Q. Mr. Banner, please state your name and business address.

A. My name is Gideon Banner. My business address is 2 Hanson Place, Brooklyn, New York 11217.

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

A. I am employed by the Service Company and currently hold the position of Principal Analyst for Strategy and Policy in the Distributed Energy Resources ("DER") group. My primary responsibilities include development of strategy and policy related to clean energy, demand-side management, and future utility business models.

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Arts in Theatre Studies from Yale University and a Master of Business Administration from the New York University Stern School of Business. I joined National Grid in 2018 and have held roles in Operations Support and Commercial Portfolio Performance prior to my current role.

II. Purpose of Testimony

Q. What is the purpose of the Panel's testimony?

A. The purpose of the Panel's testimony is to describe how the Company's proposals in these proceedings are consistent with the CLCPA. The Commission has determined that Sections 7(2) and 7(3) of the CLCPA apply to rate cases. Under Section 7(2), the Commission must determine whether approving the rate case would be "inconsistent with or will interfere with the attainment of the statewide greenhouse gas emissions limits established" in the CLCPA. Under Section 7(3), the Commission must determine whether approving the rate case would "disproportionately burden disadvantaged communities" and shall also "prioritize reductions of greenhouse gas emissions and co-pollutants in disadvantaged communities . . . ."

In addition to describing how the Company's rate case filings are consistent with the CLCPA, the Panel also describes how the Company addressed other CLCPA-related requirements, such as those established in the Commission's "Order on Implementation of the Climate Leadership and Community Protection Act" (Issued and Effective May 12, 2022) in Case 22-M-0149 ("CLCPA Implementation Order") and "Order Adopting Gas System Planning Process" (Issued and Effective May 12, 2022) in Case 20-G-0131 ("Gas System Planning Order"). The Panel also describes CLCPA-related commitments established in the Company's rate plans in Cases 20-E-0380 and 20-G-0381 (the "2020 NMPC Rate Cases") and how the Company has addressed those commitments.

Finally, the Panel describes the Company's proposed earnings adjustment mechanisms ("EAMs"), which aim to further enable greenhouse gas ("GHG") emissions reductions, system efficiency, and benefits for Disadvantaged Communities in accordance with the CLCPA's goals.

Q. How do the Company's electric and gas rate cases align with the CLCPA-related matters underway in the State?

A. The Company's rate proposals are primarily for the purpose of setting the Company's rates and revenue levels to enable it to continue to provide safe

and reliable service to customers at just and reasonable rates over the period covered by the proposed rate plans. Consistent with this primary purpose, the Company also must comply with all applicable legal and regulatory requirements, whether established by law, the Commission, or other relevant authority.

Although the proposals presented in this case relate to many of the same issues being considered in the Commission's generic policy proceedings, the Company is not attempting to establish new policy directions in these rate cases. Instead, as discussed throughout the Company's pre-filed testimony, the Company is proposing to advance targeted, "no-regrets" solutions for addressing the State's carbon reduction and other energy policy goals as part of these proceedings, while allowing the larger policy decisions to take place in the generic proceedings, as well as in other regulatory agencies' rulemakings and at the State legislature as appropriate.

Q. Does the Panel address the Company's approach to Non-Pipe Alternatives ("NPAs") in these cases?

A. Yes. The Company, as well as other National Grid affiliates, have been working to implement NPAs for several years as potential alternatives to

replacing aged, gas infrastructure and reducing the need for new capital investment in the gas system. In this testimony, the Panel describes the Company's efforts to date and proposed changes to the NPA process based on lessons learned.

Q. Please summarize the projected emissions impacts from the Company's proposals in these proceedings.

A. The proposals included in the Company's rate case filings are projected to achieve cumulative GHG emissions reductions of at least 564,000 metric tons carbon dioxide equivalent ("MT CO_2e") over the proposed rate plan period. By the end of that period, the Company estimates that the initiatives presented in these cases will result in annual GHG emissions reductions of 252,000 MT CO_2e compared to pre-rate case levels. More information on estimated GHG emissions impacts is presented later in the Panel's testimony and exhibits. The initiatives proposed in these cases also will enable greater reductions in GHG emissions in years beyond the term of the rate plan and will help the State advance toward the GHG emissions limits called for in the CLCPA.

Q. How would the Company's proposals affect Disadvantaged Communities?

A. Niagara Mohawk's service territory is geographically large and diverse. The Company serves customers in Disadvantaged Communities in densely populated urban areas such as Buffalo, Syracuse, and Albany, as well as in sparsely populated areas in the North Country, Mohawk Valley, and Central New York. As summarized herein, the projects and programs the Company proposes in these filings would prioritize customers in Disadvantaged Communities throughout the service territory and would not disproportionately impact any Disadvantaged Community. Programs specifically designed to benefit customers in Disadvantaged Communities are summarized in the Panel's testimony and described in more detail in the testimony of the Customer Panel. Also, as described in the testimony of the Electric Infrastructure and Operations Panel ("EIOP"), Gas Infrastructure and Operations Panel ("GIOP"), and Customer Panel, and summarized below, the Company is implementing practices to better assess and manage the impacts of the Company's initiatives on Disadvantaged Communities.

Q. What other CLCPA-related initiatives does the Panel address?

A. The Panel describes steps the Company is taking in response to requirements from the CLCPA Implementation Order and the Gas System Planning Order, as well as the CLCPA-related commitments established

in the Joint Proposal adopted by the Commission in the 2020 NMPC Rate Cases.

Q. Is the Panel sponsoring any exhibits as part of the testimony?

A. Yes. The following exhibits were prepared or compiled under the Panel's direction and supervision:

(i) Exhibit___(CLCPA-1): 1990 and 2022 Baseline GHG Emissions, Scopes 1, 2, and 3.

(ii) Exhibit___(CLCPA-2): Estimated GHG Emissions Impacts from Gas and Electric Operations (Rate Year – Data Year 3).

(iii) Exhibit___(CLCPA-3): "Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization" (May 2024).

(iv) Exhibit___(CLCPA-4): Gas Demand Response EAM Methodology.

(v) Exhibit___(CLCPA-5): Earnings Adjustment Mechanism ("EAM") Targets.

(vi) Exhibit___(CLCPA-6): EAM Basis Points and Incentives.

(vii) Exhibit___(CLCPA-7): Summary of EAM Net Benefits.

(viii) Exhibit___(CLCPA-8): Electric Demand Response EAM Net Benefits.

(ix) Exhibit___(CLCPA-9): Gas Demand Response EAM Net Benefits.

(x) Exhibit___(CLCPA-10): DER Utilization EAM Net Benefits.

(xi) Exhibit___(CLCPA-11): EV Managed Charging EAM Net Benefits.

(xii) Exhibit___(CLCPA-12): Medium and Heavy-Duty Transportation Electrification EAM Net Benefits.

III. CLCPA Consistency

A. Commitment to the Clean Energy Transition and CLCPA Goals

Q. What is the CLCPA?

A. The CLCPA is among the most comprehensive and ambitious climate laws in the country. It established specific targets to reduce statewide GHG emissions by at least 40 percent from 1990 levels by 2030, and at least 85 percent from 1990 levels by 2050. The law also sets certain electric-sector specific targets, including that the State's jurisdictional electric utilities procure at least 70 percent of the State's electric load from renewable energy resources by 2030, and that by 2040, the statewide electric demand system is zero emissions. The CLCPA requires procurement of at least six

gigawatts ("GW") of distributed photovoltaic solar generation by 2025, three GW of energy storage by 2030, and nine GW of offshore wind generation by 2035.

In addition to these emissions reduction and electric sector requirements, the CLCPA prioritizes the interests of New Yorkers in Disadvantaged Communities to ensure such communities realize benefits from the energy transition and are not disproportionately burdened.

Q. Please summarize National Grid's commitment to New York's clean energy future and the goals of the CLCPA.

A. National Grid's vision is to be at the heart of a clean, fair, and affordable energy future. The importance of moving to a low-carbon future cannot be overstated. At the same time, the transition must be fair and equitable, ensuring all customers, particularly the most vulnerable, have the opportunity to benefit from the transition; it should avoid harm to Disadvantaged Communities; and it must be affordable, so no customers are left behind.

The clean energy transition also must safely and reliably meet customers' energy needs. If the process of transitioning to a decarbonized energy

system erodes reliability, it will adversely impact the health and economic wellbeing of the State and its citizens and reduce the public's trust in the benefits of the transition, which could derail the ability to reach our decarbonization goals.

As summarized in the Panel's testimony and described in detail in the testimony of other panels in these cases, the Company is firmly committed to advancing the clean energy transition and the goals of the CLCPA in a way that is fair, equitable, and benefits all customers in the State.

B. Commitments in Prior Rate Cases

Q. Please summarize the CLCPA-related commitments from the 2020 NMPC Rate Cases that the Panel addresses.

A. The Joint Proposal adopted in the 2020 NMPC Rate Cases covers a range of CLCPA-related commitments. The Panel summarizes those commitments related to reports, filings, or information the Company was required to submit to the Commission prior to or concurrent with these rate case filings.

Under Joint Proposal Section IV.18.1, the Company is required to submit semi-annual filings on April 30 and October 31 of each year that report

progress on billed gas usage reduction goals. Before the end of Rate Year 2 (ended June 30, 2023), the Company also was required to file a report that assessed the energy efficiency and non-infrastructure programs needed to achieve climate appropriate reductions in billed gas usage in future years. Joint Proposal Section IV.18.1.5 requires that, beginning in Rate Year 2, the Company annually identify at least five segments of leak-prone pipe ("LPP") that could be removed if all affected customers' natural gas loads could be met with cost-effective NPAs that would allow the LPP to be removed. The Company is further required to report the LPP/NPA information in its semi-annual reports. The Company filed its most recent Billed Gas Usage Reduction and LPP/NPA semi-annual report on April 30, 2024. Likewise, the Company satisfied the requirement for filing a report assessing energy efficiency and non-infrastructure programs needed to achieve reductions in billed gas usage in future years when it submitted the CLCPA Study on March 17, 2023 in Case 20-G-0381. The Panel further discusses the CLCPA Study, below.

Section IV.18.1.6 of the Joint Proposal requires the Company to provide in this rate filing (unless required to do so earlier) the following information:

(a) A 1990 GHG emissions baseline (including Scope 1, 2, and 3 emissions) for its gas network and a description of the methodology used to calculate or otherwise develop the baseline;

(b) A calculation of a current annual GHG emissions baseline for the Company at the time of filing (including Scope 1, 2, and 3 emissions) and a description of the methodology used to calculate the emissions;

(c) An assessment of the impact that investments, programs, and initiatives described in the rate case filing will have on the Company's GHG emissions from its gas network, including a breakdown of the emissions impact of specific programs and investments proposed in the filing; and

(d) An analysis of NPAs considered for each investment, program, or initiative, including an explanation if an NPA option was not selected.

Exhibit __ (CLCPA-1) provides the 1990 and calendar year ("CY") 2022 baseline estimates for Scope 1, 2, and 3 gas emissions. Exhibit __ (CLCPA-2) provides estimates of the GHG emissions impacts of the gas and electric investments and initiatives proposed in these cases. The Panel describes the quantification of those emissions based on detailed

assessments performed by the Company. This Panel and the direct testimony of the GIOP also address the Company's approach to potential NPAs to infrastructure investments.

In addition, Section IV.18.1.3 of the Joint Proposal required the Company to complete a report by March 31, 2023, to analyze, among other things, the scale, timing, costs, risks, sensitivities, and customer bill impacts, of a range of strategies, or pathways, for achieving significant GHG emissions reductions for the use of gas delivered by the Company, including identifying projects and programs needed to achieve the State's decarbonization goals (the "CLCPA Study"). As noted above, the Company filed the CLCPA Study with the Commission on March 17, 2023.

C. CLCPA Implementation Order and the Gas System Planning Order

Q. Summarize the requirements from the CLCPA Implementation Order that apply to the Company's rate case filings.

A. The Commission's CLCPA Implementation Order directed all New York gas utilities to file a GHG emissions reductions pathways study proposal by March 31, 2023, and in future rate case filings to include an assessment

of the GHG emissions impacts of each specific investment, capital expenditure, program, and initiative included in such rate filings, and describe the investments and programs needed to achieve the objectives described in the study proposal. The CLCPA Implementation Order also directed the State's gas utilities to work with Department of Public Service Staff ("Staff") to develop a proposal for an annual GHG emissions inventory report to be filed by December 1, 2022.

The Company, together with the State's other gas utilities, filed the pathways study proposal on March 31, 2023. The Company also joined the State's other gas utilities to file a proposed GHG emissions inventory reporting proposal on December 1, 2022, which the utilities supplemented May 31, 2023.

The Gas System Planning Order directed the State's gas utilities to submit long-term gas plans on a three-year cycle, with the Company's initial long-term plan to be filed by May 31, 2024, followed by a comprehensive stakeholder process, leading to a final long-term plan filing. The order also directed the Company and other gas utilities to file NPA screening and suitability criteria, as well as cost recovery and incentive procedures, which the utilities filed on August 10, 2022. The Gas System Planning

Order further directed the State's gas utilities to perform updated depreciation studies that reflected significant reductions in customer base and volume of gas delivered. The Company filed an updated depreciation study on November 8, 2022, and supplemented the depreciation study on January 31, 2023 and March 17, 2023.

D. Consistency with the Gas Companies' CLCPA Study

Q. Please describe how the Company's rate cases are consistent with the GHG emissions reduction pathways study the Company performed to analyze the impacts of the CLCPA on its gas business.

A. The Joint Proposal in the 2020 NMPC Rate Cases required the Company to complete a CLCPA Study to "analyze[] the scale, timing, costs, and customer bill impacts of achieving significant, quantifiable reductions in carbon emissions from the use of gas delivered in its service territory and the projects and programs needed to achieve the CLCPA's specific decarbonization goals, while prioritizing reductions of greenhouse gas emissions and co-pollutants in disadvantaged communities." (Order Adopting the Joint Proposal at page 86). The Joint Proposal also provided that the Study would "identify potential barriers to achieving the targeted carbon emissions reductions and recommended solutions" and "incorporate and respond to any findings or guidance of the New York

State Climate Action Council." (Joint Proposal at page 115) The CLCPA Study analyzed impacts and barriers based on three decarbonization pathways: two electrification-focused scenarios identified in the Climate Action Council's Integration Analysis and a third pathway that continues to utilize gas network infrastructure as part of a "hybrid" approach to meet emissions reduction targets.

Q. What are the main findings of the Company's CLCPA Study?

A. Key findings from the CLCPA Study include:

- Many essential next steps to enable decarbonization are common across all decarbonization pathways. These include increasing funding to support energy efficiency and customer-side technologies, policies to support development of supply and integration of renewable fuels and energy, as well as ensuring improved coordination and planning across gas and electric networks.
- The extent of customer-side and energy system investments needed to achieve building decarbonization means affordability and equity considerations must be prioritized and addressed. Policy and regulatory decisions should provide particular support for low- and moderate-income ("LMI") customers and Disadvantaged Communities, and minimize adverse cost impacts.

- In all scenarios, gas customer counts and delivery volumes are projected to decline. This decline raises challenges to long-term gas network affordability that must be addressed through regulatory and policy reforms, including changes to depreciation, potentially in combination with additional approaches to support recovery of gas network costs, while protecting Disadvantaged Communities and LMI customers.
- Achieving net zero will be costly under any scenario, but the strategies that continue to utilize gas network infrastructure support a more affordable pathway to net zero through lower energy system and total customer costs compared to alternatives that electrify the vast majority of heating demand. Mitigation of electric peak demand growth through the utilization of hybrid heating systems is a major source of energy system cost savings.

Q. Does the CLCPA Study recommend specific actions?

A. Yes, the CLCPA Study identified several next steps based on the decarbonization pathways analysis. Given the commonalities across decarbonization pathways, the next steps are not dependent on selection of a specific pathway, and they address "no-regrets" focus areas: (i) affordability and equity, (ii) infrastructure, (iii) technology and workforce, and (iv) demand reduction.

With respect to affordability and equity, recommended next steps include programs and initiatives targeting incentives to LMI customers and Disadvantaged Communities, consideration of opportunities to prioritize delivery of infrastructure benefits to Disadvantaged Communities, and consideration of modified depreciation approaches for gas infrastructure to ensure intergenerational equity over the long-term use of gas networks.

With respect to infrastructure, recommended next steps include LPP reduction strategies to prioritize near-term safety and emissions benefits, while assessing potential options to avoid infrastructure investment (*e.g.*, NPAs); development of community-scale network geothermal systems to retire LPP or reduce gas demand; support for development of in-state RNG production; and planning for development of hydrogen blending infrastructure.

With respect to technology and workforce, recommended next steps include advancing network geothermal and initiatives to support clean energy workforce development across decarbonization technologies.

With respect to demand reduction, recommended next steps include expanded energy efficiency and gas demand response programs and

incentives; supporting customer education pertaining to program offerings and technology options; supporting efforts to expand the energy efficiency workforce; exploring innovative customer financing options; and continued evaluation of NPAs to avoid infrastructure investment and address capacity constraints.

Q. Are the Company's proposals in these proceedings consistent with these recommended next steps?

A. Yes. As described in this testimony, and as discussed in more detail in the testimony of the Customer Panel, the Company is proposing several initiatives designed to support affordability and benefit low-income customers and Disadvantaged Communities. These include additional personnel focused on serving the needs of the diverse groups of customers that comprise these customer segments by adding three Consumer Advocates, adding three Energy Affordability Program ("EAP") agents, and creating the new Indigenous Communities Liaison position. The Company also is proposing a no-fee credit card/debit card payment model, which will benefit low-income customers.

The Company also is proposing to add seven contact center representatives dedicated to serving the small-to-medium commercial customer segment.

Many of these businesses are owned by individuals who are also residential customers; and approximately 25 percent of these small-to-medium business customers are located in Disadvantaged Communities. The incremental contact center support is intended to engage this customer segment more effectively in available clean energy/energy transition services to advance the objectives of the CLCPA.

The Company also is proposing an LMI Battery Virtual Power Plant, which would provide batteries to low-income customers located on constrained feeders, thereby enabling more LMI customers to participate in clean energy efforts, increase their resiliency during outages, and support the safety and reliability of the local electric system.

As described by the Customer Panel, the Company also is proposing substantial energy efficiency initiatives consistent with the New Efficiency New York ("NE:NY") proceeding in Case 18-M-0084, as well as initiatives designed to reduce energy demand and promote long-term energy efficiency.

Furthermore, the Company's Depreciation Panel is proposing changes to its gas capital plant depreciation methodologies to begin addressing the

goal of intergenerational equity in light of anticipated future demand reductions. In summary, the Company's proposals in these proceedings are consistent with and would substantially advance the recommendations in the CLCPA Study.

E. Consistency with the Climate Action Council's Scoping Plan

Q. Do the Company's proposals in this case align with the Scoping Plan issued by the New York State Climate Action Council?

A. Yes. The Company's proposals in these proceedings recognize the need to substantially accelerate and expand energy efficiency in buildings, and to promote greater electrification of heating and transportation by 2050. Among the key findings from the Scoping Plan's integration analyses for achieving the CLCPA's emissions reduction goals are that energy efficiency and greater end-use electrification are essential parts of all pathways. The Scoping Plan also calls for "a substantial reduction in fossil natural gas use and strategic downsizing and decarbonization of the gas system," (Scoping Plan at page 350) and recognizes the role renewable fuels may play "to meet customer needs for space heating or process use where electrification is not yet feasible or to decarbonize the gas system as it transitions." (Scoping Plan at page 361).

Importantly, the Scoping Plan also recognizes the obligation of electric and gas utilities to provide safe and reliable service to customers, and the need for ongoing system investment to meet these obligations. As the Commission has stressed, failure to maintain safe and adequate electric and gas systems throughout the State during the energy transition would undermine the intent of the CLCPA.

IV. Estimated Emissions Impacts

Q. How does the Panel present the GHG emissions impacts associated with proposals in the cases?

A. To the extent a project or initiative proposed in these proceedings is expected to have a material impact on GHG emissions, the respective workstream sponsoring that measure (*e.g.*, GIOP, Gas Safety Panel, or the Customer Panel) describes the GHG impact associated with the project or initiative. The Panel compiles and summarizes the collective GHG emissions impacts identified by each of the separate workstreams.

Q. What process or methodology did the Company use to estimate the GHG emissions impacts?

A. Working with each of the workstreams, the Panel determined the emissions change expected to result from the implementation of a particular measure.

The details of how those amounts were estimated are dependent on the nature of the proposed program or initiative. For example, emissions impacts from LPP retirements are based on reduced fugitive methane emissions and are calculated using accepted emissions factors based on the type of pipe and the length of pipe replaced; whereas emissions impacts from energy efficiency programs are based on projected reductions in energy consumption by customers and the corresponding emissions profile of the avoided energy. To provide a common basis for assessment, the GHG emissions impacts are presented in carbon dioxide equivalent ("CO_2e") and a 20-year global warming potential ("GWP") using the New York State-specific methodologies for GHG where available.

The New York-specific emission factors were sourced from the November 2022 New York State Oil and Gas Emissions Inventory, the New York State Department of Environmental Conversation ("DEC") "2023 Statewide GHG Emissions Report," and the New York State Energy Research and Development Authority ("NYSERDA") "Energy Sector Greenhouse Gas Emissions" (December 2022). In cases where a New York-specific emission factor was not available, accepted emission factors from the EPA were utilized. For example, the EPA Emissions & Generation Resource

Integrated Database ("eGRID") emission factors were applied to calculate emissions reductions associated with electricity savings.

Q. What are the results of the Company's assessment of the estimated GHG emissions impacts of the initiatives proposed in these cases?

A. In the Rate Year, the proposed projects and programs are estimated to result in a cumulative reduction of at least 49,000 MT CO_2e compared to emissions immediately preceding the Rate Year. By the end of Data Year 3, assuming adoption of the proposals in these cases, the Company is projected to have reduced annual emissions compared to pre-rate period levels by at least 252,000 MT CO_2e. Over the proposed rate plan period, the Company projects to achieve estimated, cumulative emissions reductions of nearly 564,000 MT CO_2e.

Table 1, below, provides a summary of the estimated GHG emissions reductions by major program area by year for Niagara Mohawk's gas and electric operations.

Table 1 – GHG Emissions Reductions (MT CO_2e)

Program Area	Rate Year	Data Year 1	Data Year 2	Data Year 3	Total
GIOP	15,772	31,576	48,982	95,135	191,465

EIOP	-	-	-	1,175	1,175
Customer	33,151	70,291	110,582	152,996	367,020
Facilities/Fleet	229	481	757	2,786	4,253
Total	49,152	102,348	160,321	252,092	563,913

See also Exhibit __ (CLCPA-2). The Panel summarizes the bases of the estimated emissions impacts, and specific information on programs and initiatives that contribute to the estimated emissions reductions is provided in the respective testimony of the indicated program area.

Q. How do the Company's estimated GHG emissions reductions address growth from increased demand and customer additions?

A. As set forth in the direct testimony of the Gas Load Forecasting Panel, comparing actual gas deliveries to the forecasts will depend on how actual conditions compare to the Company's projections. Actual gas demand will also depend highly on weather, and can be influenced by emergent factors, such as new laws or policies, and the economy. The Company's forecast reflects the anticipated impact of known policies and programs to reduce demand, promote efficiency, and support electrification. Although the Company is actively pursuing additional policies and initiatives to reduce GHG emissions, the Company must plan based on currently known policies and activities to ensure safe and reliable service.

Nevertheless, the emissions reductions initiatives included in this case and that are summarized in Exhibit__(CLCPA-2) are generally independent of, and not expected to be impacted materially by, the overall level of gas usage within the typical margins of forecast error.

Regarding customer additions, when contacted by applicants for new gas service, the Company advises them of the availability of electric options, including the availability of rebates or other incentives. Nevertheless, the Company has an obligation to connect and provide service to qualifying new gas customers. Therefore, in the estimated GHG emissions impacts shown in Exhibit__(CLCPA-2), the Company includes estimated increased emissions related to new gas customer connections in each year of the proposed rate plan.

Regarding increased customer electric demand associated with heat pump conversions, the net GHG emissions impacts of customers converting to heat pumps from other heating sources (*e.g.*, natural gas, electric resistance heating, propane, *etc.*) are reflected in the estimated emissions values of the Company's energy efficiency and beneficial electrification programs.

Q. What is the Company doing to encourage decarbonization of heat?

A. The decarbonization of heat is uniquely challenging. Solutions are needed that are cost-effective, minimize customer disruptions, and achieve GHG emissions reductions. The Company has considered how best to achieve the CLCPA's emissions goals while still maintaining safe and reliable service and assuring that no customers are disproportionately burdened by the transition. To that end, the Company identified four primary pillars to enable the energy transition:

- First, accelerating insulation and energy efficiency improvements to buildings;
- Second, supporting cost-effective, targeted electrification on the gas network to electrify as much as 50 percent of the heating load by 2050;
- Third, in areas where full electrification may not be practical or cost-effective, providing customers with the tools to pair electric heat pumps with their gas appliances;
- Fourth, and finally, eliminating fossil fuels from our existing gas network no later than 2050 by delivering RNG and green hydrogen to customers.

This portfolio approach is intended to support affordability of achieving emissions targets by moderating the amount of required new electric system infrastructure and magnitude of up-front costs to customers,

support customer choice, and support energy system resilience through the complementary use of decarbonized electric and gas systems.

Q. How do NPAs fit into the Company's approach to proposed infrastructure investment and the decarbonization of heat?

A. The Company recognizes the importance of NPAs to identify cost-effective solutions to addressing customers' energy needs in ways that can reduce GHG emissions and enable lower overall capital investment in the gas delivery system. National Grid and RMI recently co-authored a paper entitled "Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization," a copy of which is provided in Exhibit__(CLCPA-3) ("NPA Paper"). The NPA Paper presents several case studies from the U.S. and Europe of efforts to decommission existing gas infrastructure, and it presents insights for further exploration to advance the deployment of NPAs and integrated energy planning.

In this case, the Company is proposing to build upon the NPA provisions established in the 2020 NMPC Rate Cases, adjusted for lessons learned through experience and research over the past few years, and to incorporate some of the NPA process improvements established in the 2023 KEDNY and KEDLI Rate Cases Joint Proposal.

The GIOP direct testimony presents more specifics on the Company's plans to advance NPAs as possible alternatives to addressing LPP, and avoiding or reducing gas system reinforcement projects, main extensions, and service line installations or replacements.

Q. What has been the Company's experience with NPA implementation under the current rate plan?

A. The Company has actively engaged in trying to identify and implement NPAs. To date, the Company has implemented one NPA, and has learned much along the way about practical considerations that affect the viability and potential success of NPAs. As required by the Gas System Planning Order, the Company, along with its downstate affiliates, filed NPA Screening and Suitability Criteria on August 10, 2022. The NPA screening criteria are intended to identify projects that meet certain cost and implementation time thresholds to justify full-scale NPA evaluation. Projects that pass the initial screening criteria are evaluated more closely based on the suitability criteria in terms of costs, size of the load relief needed, and available timeline, among other factors, to determine the feasibility of proceeding with an NPA. If an NPA appears to be feasible, the Company considers how it could source and procure the measures that would comprise the NPA portfolio.

One of the primary challenges the Company has faced with NPA implementation is obtaining sufficient agreement from all affected customers to enable the decommissioning or avoidance of the target gas system assets. For example, deploying an NPA as an alternative to replacing LPP may require that all existing gas customers who are served from that section of LPP agree to disconnect from the gas system. The greater the number of customers served by a section of LPP, the more difficult it is to persuade all customers to disconnect from the system.

Q. Please describe the NPA the Company implemented.

A. In 2022, the Company identified 19 homes in the Gansevoort, New York, area that were each served directly by a connection to gas transmission infrastructure, a configuration known as a "farm tap." To bring those connections to updated safety standards, the connections required installation of new natural gas regulator equipment. Of the 19 farm tap customers, five expressed interest in electrification. Following personalized outreach, three of the customers moved forward with full electrification. The electrification of the three customers will enable the Company to retire 586 feet of gas pipe and avoid the need to install three new regulators.

Q. How was the Gansevoort NPA project funded?

A. The Gansevoort NPA scope included avoiding new gas regulators for the participating customers, retiring the respective gas pipe serving those customers, the cost of installing individual geothermal heating systems, and gas appliance conversions for each customer. National Grid proposed covering the full cost of installing geothermal heating systems for each of the 19 homes, including gas appliance conversions, utilizing shareholder funds. As implemented, the total costs to electrify the three customers was approximately $350,000.

The Company's ability to implement the Gansevoort NPA was primarily because all customers served by the farm tap did not have to electrify. Indeed, only three of the potential 19 customers chose to electrify; and thus, although the Company was able to reduce some gas system investment, it still had to invest in 16 gas regulators to maintain system safety. Nevertheless, the transition of the three customers provided important learnings.

Q. What changes is the Company proposing to address the challenges it has encountered to date with the NPA program?

A. Based on lessons learned from its own programs, as well as the experience of its affiliates and information from peer utilities and other sources, the Company plans to enhance its customer outreach and engagement on NPAs with incremental resources as described by the GIOP testimony and the Customer Panel. The Company also will continue to actively advise applicants for new or expanded gas service of the availability of electric options, including the availability of rebates or other incentives to offset the costs of such options.

Q. What other steps is the Company taking to encourage more NPAs?

A. The Company will continue to look for opportunities to advance NPAs and plans to continue current NPA commitments, such as annually submitting a request for proposal for NPA solutions and to identify at least five LPP projects that could be replaced with NPAs. When considering potential NPA opportunities, the Company will focus on those with fewer impacted customers, which will reduce the chances of an NPA failing when customer consensus is otherwise needed to avoid the gas system investment.

The Company also will continue to advance the Troy and Syracuse proposed utility thermal energy network ("UTEN") projects in accordance with the Commission's "Order On Developing Thermal Energy Networks

Pursuant to the Utility Thermal Energy Network and Jobs Act," (Issued and Effective September 15, 2022), and the Commission's "Order Providing Guidance on Development of Utility Thermal Energy Network Pilot Projects," (Issued and Effective September 14, 2023) in Case 22-M-0429. More details on how the Company proposes to implement the NPA program are described in the GIOP testimony.

Q. Is the Company proposing any other programs to encourage customer electrification?

A. Yes. The Company is proposing a new NPA Heat Pump Monthly Bill Credit program. The monthly bill credit would serve as an additional incentive for customers considering whether to electrify their properties as part of an NPA proposal to encourage greater adoption of electric heat pumps and increase the number of NPAs that move forward.

Q. Which customers will be eligible to receive the monthly bill credit?

A. The Company is proposing to offer the monthly bill credit to residential and small commercial non-demand customers that agree to electrify as part of an NPA project and who have agreed to disconnect from gas service. However, the Company would also consider offering a monthly or one-time credit to other service classifications on a case-by-case basis. This program

also would be limited to customers who have electric and gas service with the Company.

The Electric Rate Design Panel describes the operation of the proposed monthly bill credit further in its testimony, including how the monthly bill credit would be determined, the proposed term of the credit, and how the Company proposes to recover the costs of the credit.

Q. Is the Company proposing any initiatives to enable gas demand reduction through advanced rates?

A. Yes. The Company is proposing a Gas Advanced Rate Design Study. The Study will explore novel approaches to gas rate design by utilizing granular interval consumption data from advanced metering infrastructure ("AMI") devices to inform potential future gas rate designs that would better align with principles of cost causation, and also encourage energy conservation, efficiency, affordability, and equity. The rate study will encompass both commercial and residential service classes in the Company's service territory, and investigate components necessary to determine the efficacy of potential gas rate designs, including impacts to system peak hour and peak day, as well as customer impacts. The

Company proposes to spend $0.120 million on the rate study in Data Year 1, $0.683 million in Data Year 2, and $0.065 million in Data Year 3.

Q. Please describe further some of the other programs and investments the Company is proposing to reduce GHG emissions.

A. In addition to the NPA and UTEN initiatives described above, the Company proposes the following programs and investments:

Energy Efficiency; Customer Programs to Enhance Participation

The Company's Customer Panel describes energy efficiency programs based on savings targets established in the NE:NY Order that are projected to deliver significant GHG emissions reductions. The Company anticipates the programs may directly reduce emissions by approximately 30,000 to 40,000 MT CO_2e annually, such that by the end of Data Year 3, annual GHG emissions are projected to be approximately 153,000 MT CO_2e less than if the programs had not been implemented.

The Customer Panel also describes the Company's proposal for funding for several incremental full-time equivalent ("FTE") positions to increase and accelerate the reach and adoption of the Company's energy efficiency programs.

GIOP and Gas Safety Panel Investments

The GIOP testimony presents a number of investments that will directly reduce emissions by nearly 95,000 MT CO_2e annually by the end of the rate plan period. A substantial portion of the reductions are from the retirement of LPP. Other projects that contribute to these emissions reductions include innovative projects to facilitate the interconnection of RNG into the network to reduce upstream emissions and displace fossil natural gas. As further described in the GIOP testimony, the RNG projects will reduce local emissions to the atmosphere at the locations where the biogas is being captured, and displace fossil gas consumption. However, for purposes of the analyses in this case, the Company is only reflecting the avoided upstream emissions associated with the locally produced RNG and is not claiming the additional emissions reductions benefits associated with typical life-cycle analyses of RNG.

Likewise, the Gas Safety Panel describes several projects and programs that will directly reduce emissions. Such programs include Advanced Leak Detection and Inside Service Line Inspection, which will potentially minimize the impact and duration of emergent leaks, and enhancements to the Company's Damage Prevention program. Estimated GHG emissions

effects of these and other gas system investments and initiatives are shown in Exhibit__(CLCPA-2)

Facilities and Fleet

The Company's Shared Services Panel describes several facilities and fleet projects that will directly reduce GHG emissions. The projects include replacing existing lighting with highly efficient light-emitting diodes ("LEDs"), replacing decades-old roofs, and replacing old heating, ventilation, and air conditioning ("HVAC") systems with new, high-efficiency systems. The Company also is proposing to electrify its light duty fleet by 2030 and install associated charging infrastructure at facilities. By the end of proposed rate plan period, the Company's facilities and fleet investments together are expected to deliver emissions reductions of approximately 2,800 MT CO_2e.

Economic Development

As described in the Customer Panel testimony, the Company is proposing to discontinue the Natural Gas Capital Investment Incentive Program for applications received after the effective date of the Company's rate plan to promote alignment with the CLCPA's emission goals. The Company is proposing to continue its Economic Development and the Future of Heat,

Sustainable Gas and Economic Development, and Natural Gas Manufacturing Productivity programs. Each of these programs enables the development and deployment of new technologies as alternatives to traditional natural gas upgrades and supports more effective and efficient use of natural gas.

The Company also is redesigning several other economic development programs to prioritize benefits to Disadvantaged Communities and strengthen the clean energy industry supply chain. The proposed changes will provide a coordinated approach to prioritizing Disadvantaged Communities and stimulating growth in the clean energy economy that is required under the CLCPA.

Information Technology

The Information Technology and Digital ("IT&D") Panel supports a number of projects that provide the necessary foundation and technology infrastructure needed to realize many of the Company's clean energy initiatives. For example, the IT&D Panel supports IT investments that are needed to enable the Distributed Energy Resources Management System ("DERMS") and Advanced Distribution Management System ("ADMS") described in the EIOP testimony, which in turn are key to safe and reliable

electric system operation as increasing levels of renewable resources are interconnected to the system. As the Customer Panel describes, IT investment also is needed for adoption of the Clean Energy 2.0 system to enable the Company to implement its energy efficiency programs more effectively and efficiently, which is particularly important given the critical role increased energy efficiency will play in achieving the State's CLCPA goals. Although the effect on GHG emissions from such investments is generally indirect, such modernizing investments are nevertheless foundational and essential to the Company's ability to deliver on emissions reductions targets.

More detail on the projects listed above can be found in the respective testimonies of the GIOP, Gas Safety Panel, EIOP, and Customer Panel and corresponding exhibits.

Q. How do the Company's proposed electric system initiatives support the attainment of CLCPA goals?

A. The CLCPA has ambitious goals for electrification of the energy system: by 2030, the CLCPA requires that the electric energy used by customers in the State be produced by renewable energy systems, and by 2040, the statewide electrical demand system will be zero emissions. The State's

load serving entities are required to procure at least 6GW of solar photo voltaic energy by 2025, at least 9GW of offshore wind energy by 2035, and support interconnection of 3GW of energy storage by 2030. Staff and NYSERDA also subsequently issued their proposed roadmap to accelerate energy storage in the State to achieve a target of 6GW energy storage by 2030.

In addition to the transition from gas to electric heating described previously, the State also is preparing for the rapid electrification of transportation. As Governor Hochul announced in a November 16, 2023 press release coincident with the Commission's Electric Vehicle ("EV") Make-Ready Program midpoint review order, the State plans to go from 175,000 electric or plug-in hybrid vehicles on the road today to approximately three million by 2030. New York also was the first U.S. state to mandate statewide electric school buses. The realization of these ambitious clean energy goals requires substantial electric system investments.

The EIOP testimony describes several initiatives to enable progress towards the State's goals, including, among other things, projects and programs to enable interconnection of more DERs, increasing system

capacity to allow for greater delivery of renewable generation and increased electrification of end-use loads, and projects to support electric vehicle charging at locations along I-90 ("EV Highway"). The EIOP testimony also describes proposed investments to enhance electric system resilience at a time when society is increasing its reliance on that system, including investments identified in the Company's Climate Change Resilience Plan ("CCRP") filed with the Commission in November 2023 in Case 22-E-0222.

Q. Does the Company estimate the GHG emissions reductions it anticipates from the proposed electric projects, programs, and initiatives in this case?

A. No. The Commission's CLCPA Implementation Order in Case 22-M-0149 directed utilities to include information on GHG emissions impacts from their gas systems in all future rate cases from their proposed investments and initiatives. The electric system investments presented in this rate case will enable increased use of renewable energy and reduced reliance on fossil fuels and other GHG emissions sources, including in other sectors of the economy (*e.g.*, transportation); however, the calculation of direct GHG emissions reductions from some of these investments is hard to estimate and would rely on factors outside of the Company's control. For example, GHG

emissions effects of investments to accelerate deployment of EV charging infrastructure would depend on the adoption rate of EVs, the number and types and numbers of internal combustion engine vehicles being displaced, miles driven, and emissions profile of the electric system. Although potential GHG emissions reductions from such electric system initiatives could be calculated using a series of assumptions, the accuracy of the estimates would be dependent on the assumptions.

Other programs and investments the Company is proposing also will directly reduce GHG emissions; however, their impacts are more difficult to estimate. For example, the NPA initiative is expected to result in electric system investment to reduce overall GHG emissions, but the extent of such reductions cannot be accurately projected at this time. As explained in the EIOP testimony, the Company also will be implementing an integrated energy planning ("IEP") initiative that could produce appreciable GHG emissions reductions; however, projecting GHG emissions impacts from IEP over the course of the proposed rate plan would be speculative.

One program the Company is implementing to directly reduce GHG emissions from its electric operations is aimed at reducing leaks of sulfur hexafluoride (SF_6) gas, a potent GHG that is used as an insulating medium

in certain high-voltage electrical equipment. The estimated impacts of this program are presented above in Table 1 and reflected in Exhibit__(CLCPA-2).

V. Disadvantaged Communities

Q. What are "Disadvantaged Communities"?

A. The CLCPA defines Disadvantaged Communities as "communities that bear burdens of negative public health effects, environmental pollution, impacts of climate change, and possess certain socioeconomic criteria, or comprise high-concentrations of low- and moderate- income households, as identified pursuant to section 75-0111 of [the Environmental Conservation Law]." The law also established the State's Climate Justice Working Group ("CJWG"), and charged that group with establishing criteria for and geographically identifying Disadvantaged Communities. In March 2023, the CJWG adopted its final Disadvantaged Communities criteria, and geographically designated Disadvantaged Communities can now be identified by census tract on an interactive map that resides on the State's Climate Act website.

Q. Does the Panel address how the Company's proposed projects, programs and initiatives affect Disadvantaged Communities?

A. Yes, Niagara Mohawk has a large and diverse service territory and many of the projects and programs proposed in the case are located in Disadvantaged Communities. The Company's approach to considering Disadvantaged Communities impacts and benefits in these proceedings reflects its commitment to enabling the clean energy transition for all customers, and is informed by the specific targets and requirements articulated in the CLCPA. As the Company works to enable the clean energy transition, it is also working to ensure customers in Disadvantaged Communities benefit from improved infrastructure, expanded outreach to provide accessible, authentic engagement and representation in the Company's processes, support participation in energy efficiency and affordability programs that can help customers manage their bills, and specific community economic benefits through programs such as workforce development grants as well as Niagara Mohawk's shareholder-funded community initiatives. The Company's proposed investments and programs are intended to ensure the continued safety and reliability of service for all customers, as well as support GHG emissions reductions and improved environmental outcomes and will directly benefit customers in Disadvantaged Communities.

In addition, the Company has sought to prioritize Disadvantaged Communities in developing customer programs included in this case, which

seek to expand resources for delivering programs to these communities. The Company also is proposing to modify its existing economic development programs to focus more on how best to deliver benefits to Disadvantaged Communities. These initiatives reflect the Company's commitment to delivering the environmental, health, and energy savings benefits of its programs in support of the targets established under the CLCPA.

Q. What programs and investments is the Company proposing in these proceedings to benefit Disadvantaged Communities?

A. The Company presents several programs and investments that will provide direct benefits to Disadvantaged Communities. Additional details on each proposal can be found in the respective testimony where the proposal is presented.

Customer Initiatives

Energy efficiency is a key driver of an equitable energy transition for customers. As described by the Customer Panel, the Company is working actively to achieve CLCPA targets and embed consideration of Disadvantaged Community impacts across energy efficiency program development, including through dedicated resources to support access and deliver benefits.

The Company's EV infrastructure program also includes several design elements that provide enhanced incentives for projects located in or adjacent to Disadvantaged Communities. This encourages development of EV charging infrastructure in those locations, which can facilitate EV adoption for customers located in Disadvantaged Communities and deliver more benefits of the clean energy transition to those communities.

Also as discussed above and in the testimony of the Customer Panel, the Company is proposing modifications to its Economic Development programs to prioritize delivery of benefits in Disadvantaged Communities. Specifically, the Company proposes to modify the Brownfield Redevelopment Assistance and Main Street Revitalization programs to prioritize and provide additional funding for eligible projects in Disadvantaged Communities. The Company also is redesigning several other economic development programs to prioritize benefits to Disadvantaged Communities and strengthen the clean energy industry supply chain. The proposed changes will provide a coordinated approach to prioritizing Disadvantaged Communities and stimulating growth in the clean energy economy that is required under the CLCPA.

Earnings Adjustment Mechanisms

As discussed in Section VI, below, the Company also is proposing a Disadvantaged Community Demand Response EAM to increase demand response ("DR") program participation in Disadvantaged Communities. This EAM is designed to encourage increased enrollment in the Company's electric DR programs and will benefit underserved markets by helping customers in Disadvantaged Communities reduce their usage and corresponding energy costs during peak times, which also aligns with the CLCPA goals.

Gas System Investments

The gas network infrastructure investments proposed in this case, including LPP retirement, will lead to improved infrastructure in Disadvantaged Communities, and provide multiple benefits, including reduction of leaks and local GHG emissions, improved local air quality, and improved safety and reliability to customers in these communities who depend on gas service to meet their everyday energy needs. The project data sheets ("PDS") included as exhibits to the GIOP testimony for capital projects and programs equal or greater to $1 million per year indicate whether a Company investment is located in or reasonably could be expected to impact a Disadvantaged Community, and if so, the Company provides information

on proposed project design considerations or other actions to avoid disproportionate burdens associated with work.

The Company also is proposing to prioritize Disadvantaged Communities in the consideration of NPAs. The GIOP testimony describes a proposal to modify the value of some of the factors considered in the NPA analyses to achieve higher conversion incentives for customers in Disadvantaged Communities, thereby increasing the potential that NPAs can proceed in such areas.

Electric System Investments

The EIOP testimony describes in its direct testimony how the Company assesses whether electric system investments proposed in this case would impact a Disadvantaged Community. In the PDSs for projects with specifically identified geographic locations, the Company indicates whether a specific project directly serves a Disadvantaged Community or not (Exhibit__(EIOP-6), Exhibit__(EIOP-8), and Exhibit__(EIOP-10)). That panel also describes its methodology for estimating the proportion of proposed electric system capital program spending that will directly impact Disadvantaged Communities. Based on the Panel's assessment, it is clear

the Company is directing substantial investment aimed at serving customers in Disadvantaged Communities.

The Company is also proposing the electrification of a portion of its light duty fleet, with the large numbers of EVs planned to be deployed at facilities in or adjacent to the boundaries of Disadvantaged Communities. Because of the Company's EV program rollout, customers will directly benefit from reduced ambient noise, improved air quality, and a reduction in local GHG and co-pollutant emissions.

A summary of initiatives located in or that support Disadvantaged Communities is provided in Exhibit __ (CLCPA-5). Additional details on each project and initiative can be found in the respective sponsoring testimony.

Q. Describe the Company's approach to workforce development.

A. The Company aims to build a sustainable, systematic pipeline of diverse talent to lead the energy transition. The Company maintains a portfolio of workforce development programs, providing individuals with opportunities and skills that support the clean energy future and invest in underrepresented and historically marginalized communities that we serve.

The Company supports several types of programs, including internships and graduate development programs for college students, community investment grants to provide training or job awareness to community members to enable social mobility by entering the broader workforce, and weatherization and energy efficiency training for underserved, marginalized, and disenfranchised workers and vendors.

Two of National Grid's workforce development programs in New York include The Grid Collective and Grid for Good.

Q. What is the Grid Collective?

A. Growing NY's Green Businesses and Jobs ("The Grid Collective" or "TGC") is a statewide National Grid Program focused on providing clean energy training to local, low and moderate income, disadvantaged customers and communities as a Diversity, Equity, Inclusion, and Accessibility ("DEIA") program focused on historically underserved communities and population groups for clean energy workforce development.

The Grid Collective's principal mission is to support the clean energy transition by addressing the shortage of vendors needed to perform

weatherization and energy efficiency projects in New York (with an emphasis on the National Grid distribution regions). There are two types of TGC Program Candidates (Vendor Candidates and Workforce Candidates). Upon graduation from a certified training program, the Grid Collective Program will engage local businesses and residents to facilitate opportunities for business expansion and growth for Vendors, and careers of Vendor Owners and the Participating Workforce within the energy industry. The Grid Collective Program also supports Vendor Candidates and Workforce Candidates that demonstrate the capacity to advance into the more complex trainings and services required by National Grid operations and the broader utility and energy industries. TGC is specifically focused on attracting historically marginalized, underserved, and systemically disadvantaged (i) local businesses and (ii) local workforce, to be identified, recruited, and trained, and then to receive project and work experience on weatherization and energy efficiency training for property types in local Disadvantaged Communities.

Q. What is Grid for Good?

A. Grid for Good is National Grid's global flagship community investment program. In the U.S., Grid for Good is focused on workforce development and building a diverse talent pipeline from under-served groups, with the

goal of delivering employability focused skills to 45,000 people by 2030. We connect with organizations that support specialized programs, mentoring, professional guidance, and academic and financial support within our New York service footprint. Specifically in Upstate New York, National Grid has partnered with Northland Workforce Training Center, On Point for College, YWCA of Syracuse, and Onondaga County and 518 ElevatED.

Q. What else is the Company doing to support an equitable transition to clean energy?

A. The Company, together with its New York affiliates, is in the process of developing an equity and environmental justice policy and stakeholder engagement framework that will describe the Company's commitment to working transparently and collaboratively with stakeholders and communities to support equity and environmental justice in the clean energy transition. The Company anticipates releasing this framework in the near future.

Q. How is the Company proposing to report on its efforts to deliver benefits to Disadvantaged Communities?

A. The Company is participating in efforts coordinated by Department of Public Service Staff pursuant to the Commission's CLCPA Implementation Order regarding tracking and reporting of compliance with the CLCPA's Disadvantaged Communities mandates. The Company's most recent filing was submitted April 12, 2024, in Matter No. 23-02017. The Company will continue to report periodically as directed by the Commission and the Department.

VI. Incremental CLCPA Costs

Q. Does the Company anticipate incurring incremental costs in support of CLCPA implementation and compliance over the period covered by the rate plan proposals?

A. Yes. The CLCPA requirements will continue to be advanced through a series of state administrative rulemakings and legislative initiatives. For example, NYSERDA and DEC are currently developing the New York Cap-and-Invest program, which could be implemented as early 2025, and which could require significant Company initiatives for implementation and compliance. In addition, Commission-directed initiatives to support CLCPA objectives may drive increases in implementation and compliance costs. Costs could include analytical requirements, stakeholder engagement requirements, and compliance and reporting requirements, among others.

Q. How does the Company propose to recover such costs?

A. The Company proposes to document and defer any incremental costs arising from any rulemakings, regulatory directives, or other legal requirements related to CLCPA compliance or implementation that in aggregate exceed $0.500 million, annually.

VII. Earnings Adjustment Mechanisms

Q. How many EAMs is the Company proposing in these cases?

A. The Company is proposing six electric EAMs and one gas EAM.

A. Electric EAMs

Q. Please summarize the background for the electric EAMs the Company is proposing in this proceeding.

A. The Company developed the proposed electric EAMs to align with the Commission's "Order Adopting a Ratemaking and Utility Revenue Model Policy Framework" in Case 14-M-0101, the State's clean energy policy goals in the CLCPA, and built on the Company's current electric EAMs. The Company is proposing to continue one existing EAM without modification, and five new EAMs to further incentivize system efficiency and accelerate GHG emissions reductions.

Q. What electric EAMs is the Company proposing in this proceeding?

A. The Company is proposing the six electric EAMs described in Table 2, below:

Table 2, Proposed Electric EAMs

EAM	Description
DER Utilization	Continuation of existing EAM; incentivizes increased efficiency of solar and storage interconnections and expanded utilization of these resources
Electric DR	New EAM incentivizes increased MW participating in electric DR programs
Disadvantaged Community DR	New EAM incentivizes increased participation in DR programs in Disadvantaged Communities
Transportation Electrification - Medium Heavy-Duty Vehicles	New EAM incentivizes acceleration of MHD EVs to support targets in Advanced Clean Truck rules
Electric Vehicle Managed Charging – Residential	New EAM incentivizes Company to develop and scale customer-centric solution for residential off-peak charging to reduce marginal distribution costs
Electric Vehicle Managed Charging - Commercial & Fleet	New EAM incentivizes Company to develop and scale customer-centric solution for commercial and industrial off-peak charging

Q. Please summarize the Company's performance in the current rate plan under the electric DER Utilization EAM.

A. Under the current rate plan, the Company has enabled an estimated $930 million in net societal benefits under the DER Utilization EAM from DER

interconnections during calendar years 2021 through 2023. The Company achieved its maximum target for the DER Utilization EAM in each year, resulting in a positive revenue adjustment of $16.1 million over the course of the three-year rate plan.

Q. Please describe the DER Utilization EAM.

A. The DER Utilization EAM incentivize the Company to enhance the processes and procedures that enable electric DERs to interconnect to the Company's system, thereby helping achieve the State's clean energy goals. The metric measures the sum of the annualized megawatt hours ("MWh") from incremental DER, specifically solar and energy storage resources.

Q. What targets is the Company proposing for the DER Utilization EAM?

A. DER Utilization targets are measured by the total installed capacity (in MW) of photovoltaic ("PV") and energy storage system ("ESS") projects during a given calendar year. PV and ESS MWh are calculated separately and then combined to create a single baseline target. The targets are set to 10% (Min), 30% (Mid), and 50% (Max) above the baseline outlined below:

Table 3 – DER Utilization EAM Targets

Proposed Targets	2025		2026		2027		2028	
	MW	MWh	MW	MWh	MW	MWh	MW	MWh
Baseline	259	227,596	270	237,491	292	257,282	303	267,178
Min (+10%)	284	250,355	297	261,240	321	283,010	334	293,895
Mid (+30%)	336	325,462	351	339,613	380	367,914	395	382,064
Max (+50%)	388	488,193	405	509,419	438	551,870	455	573,096

Solar PV	MWh = MW installed * hrs/year *13.4%
Battery ESS	MWh = MW installed * 4 hrs * 365

Q. How did the Company determine these targets?

A. Proposed targets have been calculated using the same methodology used in the 2020 NMPC Rate Cases. The Company's installed photovoltaic ("PV") and energy storage system ("ESS") MW as of November 30, 2023, Niagara Mohawk's Electric Peak Load Share, and Statewide CLCPA Goals were used to determine a baseline as follows:

2025-2028 Baseline Logic	
CLCPA 2030 PV Goal	10 GW
CLCPA 2030 ESS Goal	6 GW
NG Peak Load Share	22%
NG 2030 PV Total Responsibility	2200 MW
NG 2030 ESS Total Responsibility	1320 MW
NG Installed PV	1719 MW
NG Installed ESS	115 MW
NG 2030 PV Remaining Responsibility	481MW
NG 2030 ESS Remaining Responsibility	1205 MW
Total Remaining Responsibility	1686 MW
Remaining years	6
Average Baseline per year	281 MW
Total Baseline (Rate Case)	1124 MW
2025 Baseline (23% of total)	259 MW
2026 Baseline (24% of total)	270 MW
2027 Baseline (26% of total)	292 MW
2028 Baseline (27% of total)	303 MW

Q. Please describe the Electric DR Operational MW EAM.

A. The Electric DR Operational MW EAM is intended to incentivize the Company to increase MW participation in the Company's DR Programs. This metric measures the operationally delivered MW of DR resources from all customers in the Commercial System Relief Program ("CSRP"), Distribution Load Relief Program ("DLRP"), Term- and Auto-Dynamic Load Management ("DLM"), Direct Load Control ("DLC"), and New York Independent System Operator's ("NYISO's") Special Case Resources ("SCR") programs. This EAM promotes system efficiency and grid flexibility by developing a larger and more reliable DR resource that can be

called upon to reduce peak demand and during system contingencies, which would deliver increased reliability, cost savings, and environmental benefits for customers.

Q. **How will the Company measure the Electric DR Operational MW EAM?**

A. The Company will calculate delivered MW data using the methodology for reporting 2018 – 2023 DR program data in the Annual DR Program report to measure incremental MW from Company DR programs. The Company will use data published in NYISO's Annual Report on DR Programs to measure incremental MW from NYISO's SCR program in Zone A-C, E and F. Because National Grid customers represent only a small portion of Zone D, performance there will be based on the proportion of National Grid customers' Zone D SCR enrollment compared to total Zone D SCR enrollment.

Q. How does the Company propose to set the Electric DR Operational MW EAM targets?

A. Targets for each year are set to require incremental MW reductions beyond what would be expected based on the historic five-year annual average program growth rate ("Annual DR Growth Rate"), which will be updated

each year based on the prior year's actual performance. A baseline MW reduction value for each year will be established by multiplying the Annual DR Growth Rate by the total MW delivered in the previous year. Targets will be set by multiplying the calculated baseline for each year by 1.4, 1.8, and 2.2 for the minimum, midpoint, and maximum targets, respectively.

Q. Please describe the Disadvantaged Community DR EAM metric.

A. This EAM is designed to encourage increased enrollment in the Electric DR programs by residential customers in Disadvantaged Communities. These underserved markets can benefit from increased participation in DR programs that help them reduce their peak usage. Further, the EAM aligns with the CLCPA's clean energy objectives by reducing system peak and the emissions associated with marginal generating units serving the load. As of December 31, 2023, there were 2,437 Niagara Mohawk residential customers in Disadvantaged Communities enrolled in the Company's Electric DR Programs, which accounts for approximately nine percent of the program participation. This EAM will measure the percentage increase in the annual DR Disadvantaged Communities Participation Rate. Targets for each year are determined based on exceeding the historic program participation rate ("Annual DR DAC Participation Rate") for each year this metric is measured, beginning with 2024 enrollments. The targets would

be updated each year based on the prior year's actual enrollments. Targets will be set at increases of 10 percent, 15 percent, and 20 percent above the baseline for the minimum, midpoint, and maximum targets, respectively.

Q. Describe the proposed Transportation Electrification-MHD Vehicles EAM metric.

A. This EAM is designed to encourage the Company to increase the installed capacity of EV chargers serving MHD vehicles in its service territory, while also incentivizing the Company to work with MHDV operators who are not participating in the MHDV pilot program. This is particularly important to meet New York's aggressive goals:

- 100 percent Zero-Emission Vehicles ("ZEV") School Bus Mandate: Requires all school districts to only purchase ZEV buses in 2027, and 100 percent of all buses will be electric by 2035.
- Advanced Clean Truck ("ACT") Rule: Requires manufacturers to sell an increasing percentage of MHDVs beginning with Model Year 2025 (growing from seven percent of sales in 2025 to over 40 percent in 2035).

This EAM will measure the total MW of EV chargers installed in Niagara Mohawk's territory, on an annual basis, beginning January 1, 2025, through December 31, 2027. This would be tracked through the Company's EV

Application Portal and through its operations platform (*i.e.*, STORMS). The metric would be the combined total of both program and non-program MHDV charging ports.

Q. How does the Company propose to set targets for the Transportation Electrification-MHD Vehicles EAM?

A. The minimum target would be set to reflect potential incremental MHD vehicles charging MW enabled by the Company's programs. The Company set the minimum target based on the estimated total charging capacity that could be enabled each year through its MHD pilot program. The mid and max targets reflect a 1.5x and 2.0x increase from the minimum target, respectively.

Q. Please describe the EV Managed Charging – Residential EAM metric.

A. The EV Managed Charging Residential EAM is intended to encourage the Company to maximize enrollment in and performance of its residential Managed Charging programs. These programs encourage participating EV drivers to charge their vehicles during off-peak hours to support overall system efficiency and avoid incremental electric system costs, while providing savings opportunities to EV drivers. The Company will measure the enrollment and performance of EVs in the managed charging program

shifting their load. The Company will measure the customers enrolled in VTOU using the meter and billing data for those customers. The total number of EVs in the Company's service territory will be sourced using the Polk VIO data. The metric to be evaluated will be the percent increase, relative to the previous year, in the number of participating customers having more than 80 percent of their EV charging load during off-peak hours, divided by the number of EVs in National Grid's service territory as of July 1 of the reporting year.

Q. How does the Company propose to set targets for the EV Managed Charging – Residential EAM?

A. The targets for this EAM would be based on the increase in the proportion of customers charging off peak relative to the previous year's performance. The minimum, midpoint, and maximum targets will be set at 5 percent, 15 percent, and 25 percent above the previous year's performance, respectively.

Q. Please describe the EV Managed Charging – Commercial and Fleet EAM metric.

The EV Managed Charging Commercial and Fleet EAM is intended to encourage the Company to maximize enrollment in and performance of its

Commercial Managed Charging programs. These programs encourage participating EV drivers to charge their vehicles during off-peak hours to support overall system efficiency and avoid incremental electric distribution costs. The EAM will incentivize the Company to enroll chargers in the Company's Managed Charging programs at an equal or faster rate than the growth in chargers in the service territory, such that the Company is capturing an increasing share of Commercial and Fleet EV charging in these programs. It will also encourage Participating Chargers to charge at least 80 percent of their load outside peak hours (3pm-9pm) as noted in Niagara Mohawk's Commercial Managed Charging Program Implementation Plan.

The Company will measure the enrollment and performance of chargers in the managed charging program shifting their load. The total number of chargers in the service territory will be sourced from the EValuateNY tool, maintained by Atlas Public Policy, which is updated monthly. The metric to be evaluated will be the percent increase, relative to the previous year, in the number participating chargers with more than 80 percent of their load during off-peak hours, divided by the total number of chargers in our service territory.

Q. How does the Company propose to set targets for the EV Managed Charging – Commercial and Fleet EAM?

A. The targets for this EAM would be based on the increase in the proportion of chargers charging off peak relative to the previous year's performance. The minimum, midpoint, and maximum targets would be set at 5 percent, 15 percent, and 25 percent above the previous year's performance, respectively.

B. Gas EAM

Q. Please summarize the background for the gas EAM the Company is proposing in this proceeding.

A. The Company developed the gas EAM proposal to align with the State's clean energy policy goals in the CLCPA. The Company is proposing one new Gas DR EAM that addresses system efficiency by reducing peak demand on the gas distribution network.

Q. Please describe the Gas DR EAM metric.

A. The Gas DR EAM would measure performance across the Company's portfolio of gas DR programs, the primary goal of which is to provide region-wide gas system relief during peak hours.

Q. How will the Company measure this EAM?

A. The EAM will measure the performance of the Company's firm gas DR portfolio, which is currently composed of the Load Shedding, Load Shifting, and Bring Your Own Thermostat ("BYOT") programs. That performance will be assessed in units of dekatherm ("dth")/hour. The EAM baseline will be determined using a linear regression derived from actual performance during the preceding three winter seasons. Achievement will be measured using actual performance during events.

Q. Why does the Company propose to measure performance in units of dth/hour?

A. The gas DR programs are all designed to reduce peak demand, but each program measures enrollment in different units (dth/day, dth/hour, and number of devices enrolled, for Load Shedding, Load Shifting, and BYOT, respectively). Therefore, program performance needs to be converted to a common basis for purposes of measuring the EAM. Utilizing dth/hour will: (i) enable like-for-like comparisons of events that differ in length, and (ii) encourage the Company to focus on providing the maximum event reductions needed to maintain reliable service and avoid the unintended incentive to call longer-duration events.

Q. How many years of historical data does the Company propose to use to calculate the baseline, and why?

A. The Company proposes to use the previous three winters' performance to set the baseline for the Rate Year, and to carry that methodology forward into the Data Years. Thus, the baseline for the Rate Year would be set using performance during winters 2022-2023, 2023-2024, and 2024-2025; the baseline for Data Year 1 would be set using performance during winters 2023-2024, 2024-2025, and 2025-2026; and so forth.

Q. How would the Company compute baseline and performance period achievement?

A. First, the Company proposes to use the total aggregate performance across the entire gas DR program portfolio for each gas day on which an event occurs, regardless of event type. Events can be one of three types: (1) test events, generally called either at the start of the winter season to ensure customers are prepared to perform during events later in the season, or mid-winter if no actual events have occurred; (2) actual events, called on days where the forecast average temperature is below the program temperature event threshold; or (3) emergency events, called in response to emergency conditions on the system such as constraints on upstream transmission pipelines. Second, the gas day on which the portfolio achieves its highest

peak-hour reductions during a given winter will be used to derive the baseline values and actual achievement for each winter. Due to program design, events with the highest peak hour reductions will likely correlate to the coldest days of the year. The highest peak hour reductions are calculated as the sum of the dth reductions achieved by each program during the respective gas DR event divided by the number of event hours for each program during that gas day. Exhibit__(CLCPA-4) provides an illustrative numeric and graphical representation of this methodology.

Q. Why is the Company proposing to use actual performance rather than enrollment values?

A. Using actual performance rather than enrollment to determine both the historical values used to calculate the EAM baseline and actual achievement will encourage the Company not only to increase enrollment, but also to improve customer performance during events and align with the goal of the gas DR program portfolio.

Q. How is "performance" determined during a gas DR event?

A. The methodologies use to determine performance for the Load Shedding and Load Shifting programs during events are detailed in the Company's

tariff. Performance for the BYOT program is determined using a randomized control trial methodology.

Q. If the Company were to develop new gas DR pilots or programs, would those be included in achievement on the Gas DR EAM?

A. Yes, they would, because doing so will incentivize the Company to develop new and innovative pilots, programs, and methods to reduce peak gas demand further. The Company has no specific plans for such pilots or programs at this time; however, if any new programs are considered that would contribute to achieving this EAM, the Company will consult with Staff and, if necessary, submit a filing describing the proposed methodology.

Q. How does the Company propose to set the Gas DR EAM targets?

A. The minimum, midpoint, and maximum targets will be set at four percent, eight percent, and 28 percent above the baseline, respectively.

Q. Is the proposed Gas DR EAM the same as the metric included in the Joint Proposal filed in the 2023 KEDNY and KEDLI Rate Cases?

A. The Company's affiliates in Downstate New York proposed a very similar EAM in their recently filed Joint Proposal. The primary difference between

the two is that in the Downstate proposal, the regression used to calculate the baseline is logarithmic, whereas here the Company is proposing a linear regression. This is because the Downstate New York DR portfolio is relatively mature and has already enrolled many of the largest potential customers, whereas the Company's DR programs—particularly the Load Shedding program—has a greater potential to see higher growth rates in the next few years. Thus, a linear regression, which is expected to lead to higher EAM targets than a logarithmic one, is more appropriate.

C. EAM Measurement and Achievement

Q. Please describe how customer needs and benefits were considered in developing the Company's EAM proposals.

A. The Company sought to identify metrics and targets that align with enhancing customer benefits and accelerating achievement of State policy goals. As described below, the Company's EAM proposals are supported by benefit cost analyses.

Q. Describe the targets the Company is proposing for each EAM?

A. The minimum, midpoint, and maximum targets for each metric are shown in Exhibit__(CLCPA-5).

Q. How does the Company propose to allocate basis points across EAMs?

A. The Company proposes allocating the basis points for EAMs as shown in Exhibit__(CLCPA-6).

Q. When does the Company propose the EAMs become effective?

A. EAM performance is typically measured and reported on a calendar year basis to align with annual EE program plans and implementation. The Company proposes all EAMs become effective January 1, 2025 and continue through the last calendar year of the electric and gas rate plans.

Q. How does the Company intend to report EAM results and recover incentives?

A. On April 15 of each year, the Company will make an annual compliance filing with the Commission. The filing will include a report on the Company's prior calendar year performance relative to each EAM target, showing the savings and benefits achieved, as well as the calculations for the incentives earned. For metrics where the Company's performance falls between the minimum and the mid-point target or the mid-point target and the maximum, the incentive payouts will be prorated. The Company will also provide an explanation of any targets not achieved.

Q. When would the Company begin recovering EAM incentives it earns?

A. Any incentive that is achieved would be recovered through a surcharge, as explained in the testimonies of the Electric Rate Design Panel and the Gas Rate Design Panel.

D. Benefits and Costs

Q. Did the Company analyze the portfolio of benefits and costs associated with its proposed EAMs?

A. Yes. For each EAM, the Company estimated the total value of societal benefits that would be delivered at minimum, midpoint, and maximum target levels. Electric benefit accounting includes MW, MWh, CO_2e, and non-electric fuel savings values. Gas benefit accounting includes dth and CO_2e savings values. From there, the Company subtracted total estimated costs to deliver these results. As outlined in Exhibit__(CLCPA-7), the net present value of each EAM's net benefit is positive, and incentive levels are sized so that customers retain the vast majority of net benefits across the portfolio.

Q. What did the Company's analysis of the benefits and costs conclude?

A. The Company's analysis concluded that the programs and products supporting the EAMs provide significant qualitative and quantitative benefits including increased customer choice and customer savings as well as carbon and energy usage reductions to further the goals of the CLCPA. For the Net Benefits Calculations for each EAM see Exhibit__(CLCPA-7) through Exhibit__(CLCPA-12).

VIII. Conclusion

Q. Does this conclude the Panel's testimony?

A. Yes.

EXHIBITS

Testimony of Climate Leadership and Community Protection Act Panel

Exhibit___(CLCPA-1)

1990 and 2022 Baseline GHG Emissions, Scopes 1, 2 and 3

Niagra Mohawk Gas Emissions
1990 and 2022 Baselines

Calendar Year (CY) 2022

Carbon Impact mt CO2e

		Scope 1	Scope 2	Scope 3
Gas Distribution	Fugitive Emissions from Distribution Mains	202,570		
	Fugitive Emissions from Distribution Services	403,288		
	Other Fugitive Emissions (from Mains & Services)	2,190		
	Fugitive Emissions Transmission Pipelines	14,328		
	Non-Routine Venting (PRVs, Dig ins, Blowdowns)	44,140		
	Fugitive Emissions from Meters	112,737		
	Fugitive Emissions from Stations (M&R and T-D Transfer)	734		
	Pneumatic Venting	2,077		
	Tier 1 Stationary Combustion Gas Fuel	19		
	Sold Gas (Scope 3-Category 11)			3,222,605
	Out of State Upstream Sold Gas			2,513,982

Totals	**Scope 1 (mt)**	**Scope 2 (mt)**	**Scope 3 (mt)**
	782,084	-	5,736,586

	NMPC 2022 Emissions (mt CO2e)
Scope 1 & 2 Gas Dx	782,084
Scope 3-Category 11 (Sold Gas including upstream)	5,736,586

	NMPC 1990 Baseline (mt CO2e) (1)
Scope 1 & 2 Gas Dx	2,925,078
Scope 3-Category 11 (Sold Gas)	12,580,044

(1) A ratio was applied to represent the 1990 Baseline on the basis of NY-specific factors (i.e., emission factors and GWP 20-year).

Notes
mt: metric tonnes

Testimony of Climate Leadership and Community Protection Act Panel

Exhibit___(CLCPA-2)

Estimated Greenhouse Gas Emissions Impacts from Gas and Electric Operations;
Rate Year – Data Year 3

NMPC GHG Emissions Reductions (MT CO2e)

Workstream	FY26 (Rate Year)	FY27 (Data Year 1)	FY28 (Data Year 2)	FY29 (Data Year 3)	Cumulative Emissions Reduced/Avoided Rate Year- Data Year 3
GIOP	15,772	31,576	48,982	95,135	191,465
EIOP				1,175	1,175
Customer*	33,151	70,291	110,582	152,996	367,020
Fleet/Facilities	229	481	757	2,786	4,253
Total Emissions Reduced/Avoided	49,152	102,348	160,321	252,092	563,913

* Customer program emissions based on calendar year data.

Testimony of Climate Leadership and Community Protection Act Panel

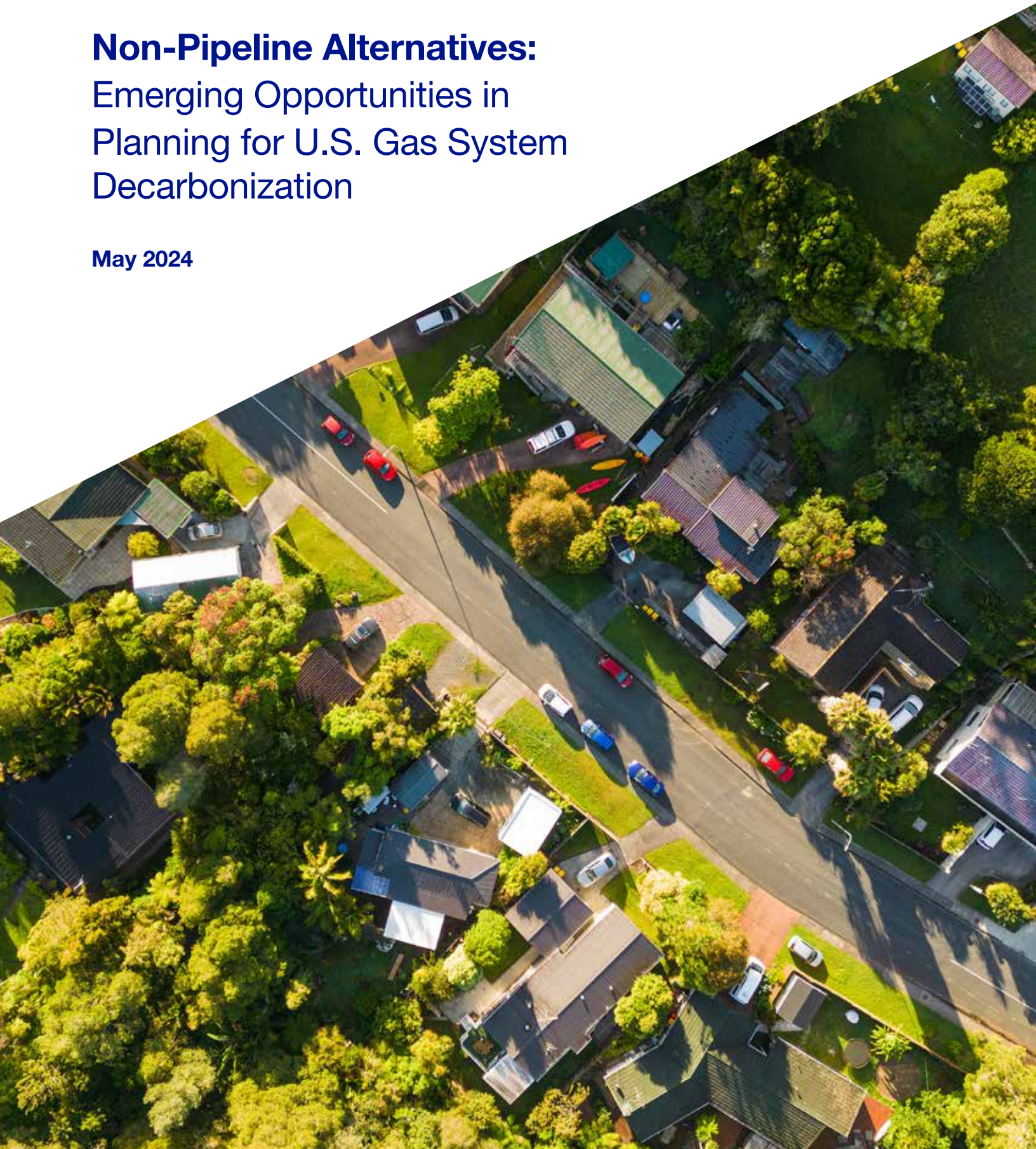
Exhibit___(CLCPA-3)

"Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization" (May 2024), paper by RMI and National Grid

RMI | nationalgrid

Non-Pipeline Alternatives:
Emerging Opportunities in Planning for U.S. Gas System Decarbonization

May 2024



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Executive Summary

Multiple states in the U.S. have adopted ambitious climate targets requiring the achievement of net-zero greenhouse gas (GHG) emissions. To meet these climate targets and utility net-zero goals, utilities, regulators, and other stakeholders have begun planning for a future that is less reliant on fossil gas and more dependent on clean energy resources. Progress towards this future can be significantly advanced through integrated energy planning and adoption of non-pipeline alternative solutions.

Integrated energy planning (IEP) is the practice of incorporating critical interactions between gas, electric, and customer energy systems into utility and energy planning processes in the context of long-term climate goals. By recognizing the interdependent nature of today's energy systems, integrated energy planning can aid in assessing the infrastructure and customer impacts of potential transition strategies. This serves to advance net-zero goals most cost-effectively and equitably, while ensuring the safety and reliability of the systems customers rely on.

Non-pipeline alternatives (NPAs) are projects or initiatives intended to simultaneously reduce GHG emissions and defer, reduce, or avoid the need to construct or upgrade components of the natural gas system through customers' installation of all-electric equipment or connection to other lower-carbon infrastructure, including thermal energy networks. NPAs are an emerging area of opportunity for gas system decarbonization in the U.S., with the potential to achieve ratepayer savings across three categories of gas network investment: replacement of existing infrastructure, capacity expansion of existing system, and system extension to new customers.

National Grid U.S. is working to advance its own planning processes in accordance with the goals of the jurisdictions in which it operates, Massachusetts and New York. In order to better understand the landscape of non-pipeline alternatives and integrated energy planning in the gas industry today, National Grid and RMI worked together to identify case studies where NPAs and integrated energy planning have been implemented or developed. This research included interviewing utilities, non-governmental organizations (NGOs), consultants, and others working to deploy NPAs and integrated energy planning in diverse jurisdictions across the U.S. and Europe.

This whitepaper is divided into two parts:

First, we present nine case studies describing the current state of NPA initiatives and integrated energy planning in the U.S. and Europe. These case studies include projects that have moved toward implementation in both the U.S. and Europe, including the decommissioning of specific gas infrastructure.

For example:

- Pacific Gas & Electric (PG&E) in California has completed 88 NPA projects, converting a total of 105 customers from gas. Other U.S. utilities advancing projects include National Grid, Con Edison, Rochester Gas and Electric, and Xcel.
- In Europe, municipal clean heat planning is prevalent or required in multiple countries including the Netherlands and Switzerland. While Zurich is the only example of a city that has completed neighborhood-scale decommissioning to date, other cities in Switzerland and elsewhere are working to follow suit.
- Combination utilities in the U.S. such as National Grid and Xcel are working to integrate internal gas and electric planning teams and develop new tools and processes for integrated energy planning. An early example of cross-utility planning can also be found in Québec, where the gas and electric utilities received regulatory approval for a joint decarbonization strategy that accounts for the benefits each system provides the other.

Then, based on our research and learnings, National Grid and RMI offer the following eight insights for further exploration by U.S. utilities, regulators, policymakers, and other stakeholders to advance the deployment of NPAs and integrated energy planning:

NPA projects underway today reflect diverse energy policy goals and energy system characteristics across different jurisdictions. Clean heat planning is generally motivated by environmental and economic concerns, while some jurisdictions are also motivated by geopolitical and equity concerns. This diversity will necessarily shape the solutions that meet each jurisdiction's goals and needs.

NPA projects can identify value in cost savings on the gas system, emissions reduction, or other societal benefits. Utilities looking to develop cost tests for NPA projects should start by identifying the key costs and benefits, which may vary by jurisdiction and emissions valuation structure.

Prioritization of NPA projects should weigh a broad set of criteria, including gas asset risk and hydraulic feasibility, electric capacity, benefit-cost criteria, customer propensity for new technology adoption, and community factors. Some near-term areas of opportunity for NPAs are high-cost gas asset replacements where there is electric headroom and fewer than five customers on a segment.

NPA projects can be funded from a series of different sources while protecting ratepayers' long-term affordability. To date, NPA projects have been funded by gas ratepayers. However, to help mitigate upward rate pressure for gas customers as gas demand declines, consideration should be given to alternative funding sources, including federal, state or local taxpayer funding, as well as electric ratepayer funding.

Integrated gas and electric network planning offers the opportunity to achieve net-zero goals as cost-effectively and equitably as possible. Regulatory support will be required to enable cross-utility data sharing and decision-making, and to invest in new tools and capabilities.

Utility and municipality partnership may be a key element of NPA projects and localized integrated energy planning. Partnering at the municipal level is a valuable way to ensure alignment, build community support, and incorporate local priorities in project planning.

In presenting this work, we hope the case studies and insights detailed herein will serve as a catalyst for advancing the implementation of NPAs and integrated energy planning across the U.S.

Individual customer persuasion to reach 100% participation is not a scalable NPA approach for avoided replacement projects. Under the current regulatory framework, NPAs that avoid infrastructure replacement require voluntary and coordinated conversion of 100% of customers on the segment from gas to all-electric equipment. To date, no U.S. utility has successfully completed this type of NPA under the existing regulatory framework for projects serving greater than five customers.

Policy change will be needed to evolve the utility business model and obligation to serve, while retaining the opportunity for cost recovery in a transition away from the use of gas. State regulators will have a critical role in overseeing substantial changes to the provision of utility service that enable NPA projects to scale.

In presenting this work, we hope the case studies and insights detailed herein will serve as a catalyst for advancing the implementation of NPAs and integrated energy planning across the U.S.

Introduction

What are non-pipeline alternatives and integrated energy planning?

Non-pipeline alternatives (NPAs) are projects or initiatives intended to simultaneously reduce GHG emissions and defer, reduce, or avoid the need to construct or upgrade components of the natural gas system. NPAs are an emerging tool providing an opportunity to reduce emissions, gas system costs, and customer risk by avoiding unnecessary gas infrastructure spending. This is achieved through the electrification of potential new or existing gas customers or connection to other carbon-free infrastructure, including thermal energy networks such as networked geothermal systems. NPA projects fall under one of three categories of avoided incremental infrastructure investment:

- **Avoided replacement** projects avoid the risk-driven replacement of an asset, including retiring the asset and converting affected customers from gas. Avoided replacement projects require targeted electrification of all gas uses by all customers connected to a given segment of pipe, in order for the investment in new infrastructure to be avoided and the asset disconnected and retired. In practice, avoided replacement projects tend to see greater success under existing regulatory frameworks when the number of customers per project is fewer than five.
- **Avoided capacity expansion** projects avoid investments driven by forecasted load growth. These projects typically do not require 100% of affected customers to participate in demand reduction measures.
- **Avoided system extension** projects avoid the extension of the gas system to new customers. Several jurisdictions address system extensions through avenues other than utility policy.

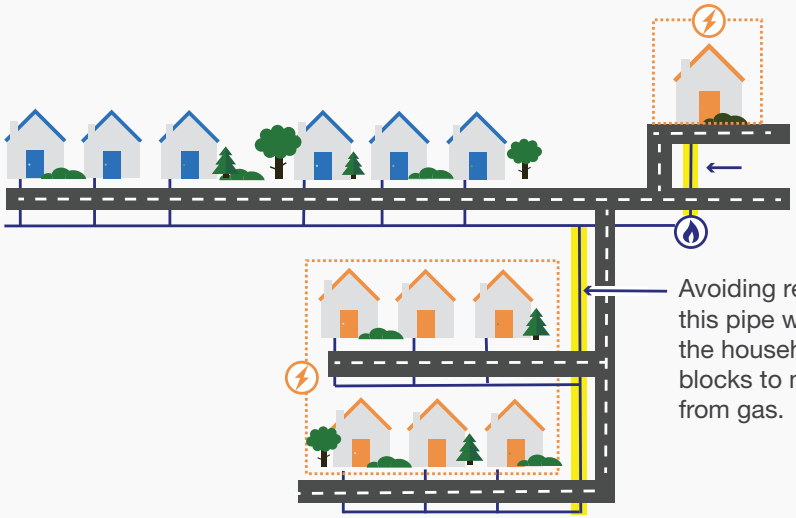
In this paper, our research primarily focuses on deploying NPAs to avoid gas infrastructure replacement or capacity expansion, including projects that involve decommissioning specific gas infrastructure. These three categories can be seen in Exhibit 1.

Integrated energy planning (IEP) is the practice of considering and incorporating critical interactions between gas, electric, and customer energy systems into utility and energy planning processes in the context of long-term climate goals, to achieve net-zero goals most cost-effectively and equitably for customers. While recognizing that IEP can provide broad value beyond NPAs, this paper focuses on the ways IEP can facilitate NPA identification and development.

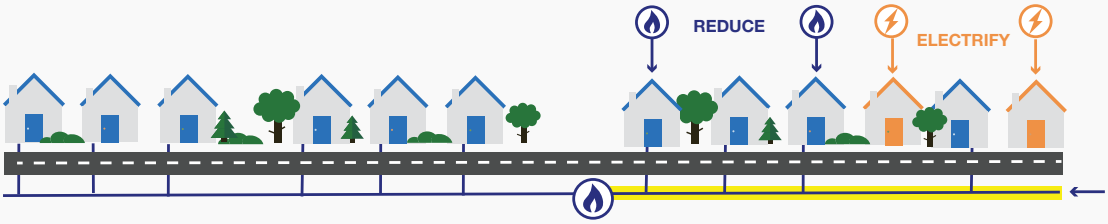
NPAs are an emerging tool providing an opportunity to reduce emissions, gas system costs, and customer risk by avoiding unnecessary gas infrastructure spending.

Exhibit 1: NPA projects fall under one of three categories of avoided incremental infrastructure investment.

Avoided replacement

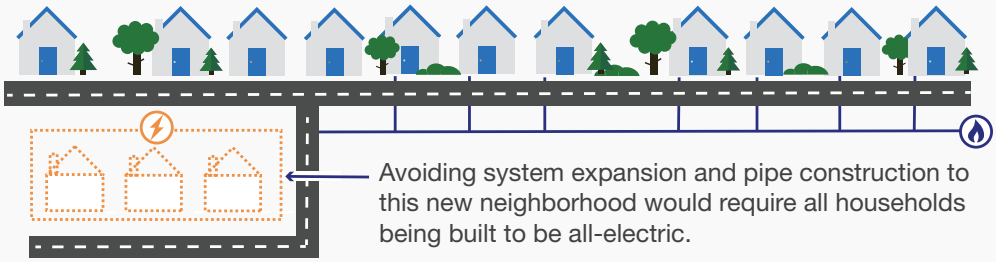


Avoided capacity expansion



To avoid a capacity upgrade for this pipe, buildings beyond this pipe segment would need to reduce their overall gas demand – this could be through incremental reductions across the group, or full electrification of some customers. This reduction would not require 100% participation of all households.

Avoided system extension



Why are these topics important?

Natural gas utilities serve over 77 million customers in the U.S. These utilities maintain and operate more than one million miles of local distribution lines and invest over $20 billion per year in distribution systems.[1] State and federal climate and energy planning processes are increasingly cognizant of significant GHG emissions from the use of natural gas and thus identify a range of strategies aimed at reducing the use of gas over time.[2] In addition, policymakers in several states have begun to grapple with potential policy issues raised by a long-term reduction in the utilization of natural gas infrastructure (referred to in this paper as "gas transition").

State and federal climate and energy planning processes are increasingly cognizant of significant GHG emissions from the use of natural gas and thus identify a range of strategies aimed at reducing the use of gas over time. In addition, policymakers in several states have begun to grapple with potential policy issues raised by a long-term reduction in the utilization of natural gas infrastructure.

Relevant Context for Non-Pipeline Alternatives in MA, NY and other U.S. States

In December 2022, New York and Massachusetts, the states in which National Grid operates, published net-zero plans calling for long-range reductions in the use of gas and new planning for gas transition policy issues. In New York, the Climate Action Council's Final Scoping Plan found that "achievement of the emission limits will entail a substantial reduction of fossil natural gas use and strategic downsizing and decarbonization of the gas system."[3] The Scoping Plan called for the "identification of strategic opportunities to retire existing pipelines as demand declines," including "seeking to move whole streets or neighborhoods at a time from gas infrastructure" to an electrified alternative.[4] The Scoping Plan further recognized the need for "integrated planning with the decarbonization of the power generation sector and buildout of local electric transmission and distribution systems" to meet increased demand and ensure equity and cost-effectiveness for customers.[5]

In Massachusetts, the Clean Energy and Climate Plan for 2050 (CECP) determined that "necessary reductions in natural gas throughput will require changes in how the gas system is operated and regulated and may require decommissioning significant parts of the gas system."[6] The CECP also found that gas distribution utilities may need to "manage customers' departure from the gas system to enable the retirement of some selected parts of the system to save some ongoing avoidable operating and/or capital investment costs."[7]

[1] This figure from 2022 (the latest year with available data) represents a four-fold increase in annual spending since 2011. "Gas Utility Construction Expenditures by Type of Facility 1972-2022," American Gas Association, 2023, https://www.aga.org/wp-content/uploads/2023/01/Table12-1.pdf.
[2] More than ten states, including Massachusetts and New York, have opened regulatory proceedings to consider how gas utility planning should evolve in line with state emissions reduction targets.
[3] New York State Climate Action Council, "New York State Climate Action Council Scoping Plan," 2022, https://climate.ny.gov/resources/scoping-plan/, at p.350.
[4] Ibid at p.351.
[5] Ibid at p.350.
[6] Massachusetts Executive Office of Energy and Environmental Affairs, "Clean Energy and Climate Plan for 2050," 2022, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050, at p.62.
[7] Ibid at p.83.

Additionally, the December 6, 2023 order in Massachusetts Department of Public Utilities (DPU) Future of Heat Proceeding 20-80 affirms the value of targeted electrification and integrated energy planning as key strategies for managing the long-term costs of the gas system.[8] The DPU emphasizes the importance of rate recovery for existing, prudently made infrastructure investments and indicates in this order that the DPU will increase its scrutiny of new investments on the gas system, including an expectation that utilities will regularly assess NPAs to projected infrastructure needs. In the Climate Compliance Plan process established by the order, gas utilities must file plans every five years detailing their alignment with emissions reduction targets. The DPU also highlights the need for better integration of gas and electric system planning and requires electric utilities to partner in the development of overlapping gas utilities' Climate Compliance Plans.

Beyond the Northeast, there are other examples of regulators and utilities evolving gas infrastructure planning to manage ratepayer costs while achieving needed emissions reductions. California and Colorado have eliminated gas line extension allowances statewide, an indication that expansion of the gas system is no longer seen as a net benefit to existing gas ratepayers.[9] Both states now also require utilities to seek approval for and evaluate alternatives to certain gas infrastructure investments above a specific cost threshold.[10] Colorado's gas planning rules, similar to the new Massachusetts DPU Climate Compliance Plans, also require utilities to regularly file plans for meeting emissions targets and managing gas system costs.[11]

In this evolving policy landscape, gas utilities should prepare for changes on their systems and find new ways to manage capital investments. Utilities need to balance the imperatives of safe and reliable service, GHG emissions reduction, and long-term customer affordability in a future with reduced gas use. In this context, IEP and NPA solutions to avoid gas system investments present important opportunities to achieve this balance.

This whitepaper aims to describe the current state of NPA solutions and gas transition planning in North America and Europe and identify projects that have moved toward implementation, including decommissioning of gas infrastructure. We further explore the potential for the expanded use of NPAs and integrated energy planning in the U.S., including the potential role of municipalities in helping coordinate planning at the neighborhood or city scale.

Gas utilities should prepare for changes on their systems and find new ways to manage capital investments. Utilities need to balance the imperatives of safe and reliable service, GHG emissions reduction, and long-term customer affordability in a future with reduced gas use.

[8] Massachusetts Department of Public Utilities, "Order on Regulatory Principles and Framework," D.P.U 20-80-B, December 6, 2023, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602.

[9] California Public Utilities Commission, "Phase III Decision Eliminating Gas Line Extension Allowances, Ten-Year Refundable Payment Option, and Fifty Percent Discount Payment Option under Gas Line Extension Rules, Decision 22-09-026," Rulemaking 19-01-011, September 15, 2022, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K987/496987290.PDF. S.B. 23-291, 74th Leg., (CO 2023), https://leg.colorado.gov/sites/default/files/2023a_291_signed.pdf.

[10] California Public Utilities Commission, "Decision Adopting Gas Infrastructure General Order," Rulemaking 20-01-007, November 30, 2022, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K396/499396103.PDF.

[11] Colorado Public Utilities Commission, "Commission Decision Adopting Rules," Proceeding No. 21R-0449G, December 1, 2022, https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_session_id=&p_dec=29605.

Case Studies

This section provides illustrations of non-pipeline alternatives and integrated energy planning from leading jurisdictions in North America and Europe. This section begins with a description of National Grid's initiatives in this area, then identifies other notable U.S. utilities advancing NPAs and IEP, and then details the most developed European examples.

National Grid US

In April 2022, National Grid published its Clean Energy Vision, which calls for achieving net-zero GHG emissions by 2050 by focusing on four pillars: energy efficiency in buildings; 100% fossil-free gas network; hybrid electric-gas heating systems; and targeted electrification and networked geothermal.[12] This vision recognizes the need for electrification of many existing gas customer end uses to achieve net-zero GHG emissions through full electrification as well as partial or hybrid electrification.

National Grid has been evaluating potential non-pipeline alternative projects in New York for several years and working with peer utilities, regulators, and stakeholders to develop supporting regulatory frameworks.[13]

More recently, in Massachusetts, National Grid has been developing networked geothermal demonstrations which could also have potential as NPAs.[14]

National Grid has been evaluating potential non-pipeline alternative projects in New York for several years, and working with peer utilities, regulators, and stakeholders to develop supporting regulatory frameworks.

NPAs for Avoiding the Replacement of Existing Infrastructure

Over the last two years in New York, National Grid has been working to identify planned gas capital projects that could potentially be avoided through targeted electrification and decommissioning of specific segments of aging gas infrastructure rather than replacement.[15] In that time, National Grid has identified 27 of these projects in its New York territory. Of the 398 customers initially contacted about these 27 potential NPA projects, 149 customers have responded (37%) and 18 have expressed interest (5%).

One of the key barriers to implementing NPA solutions that retire leak-prone pipe is the fact that 100% of affected customers must participate in the program in order to decommission the asset. In communicating with customers about the benefits of NPAs, National Grid has identified a lack of broad customer familiarity with heat pump technologies,

[12] National Grid, "Our Clean Energy Vision," April 2022, https://www.nationalgrid.com/us/fossilfree.

[13] This work has included National Grid's NPA Screening and Suitability Criteria proposal as well as the Joint Local Distribution Companies NPA Incentives and Cost Recovery proposals, filed with NYS Public Service Commission on August 10, 2022. "Joint Local Distribution Companies' Proposals for Non-Pipe Alternative Incentive Mechanism and Cost Recovery Procedures," New York Public Service Commission Case 20-G-0131, August 10, 2022, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={EBD3BFE2-6AC6-4A28-B98A-09E6A7CB75A4}. National Grid, "National Grid's Proposals for Non-Pipe Alternative Screening and Suitability Criteria," New York Public Service Commission Case 20-G-0131, August 10, 2022, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2EC93238-1BA2-4AE6-B390-0436B198391B}.

[14] The company is developing a networked geothermal demonstration project at the Boston Housing Authority's (BHA) Franklin Field in Dorchester, MA. This geothermal project will replace an aging gas boiler loop that currently serves 129 BHA units. Construction is expected to begin in 2025.

[15] These efforts have focused on specific planned gas main replacement projects that are part of ongoing capital programs to replace Leak Prone Pipe, or 'LPP,' a term used in several Northeast states to refer to infrastructure that is assessed as a leak risk, based on vintage, material, or other factors. Utilities in other regions of the U.S. may refer to this type of pipe by its 'DIMP' score, based on the federal Distribution Integrity Management Program administered by the Pipeline and Hazardous Materials Safety Administration ('PHMSA').

customer concerns about the impacts of electrification on their energy bills, customers' preferences for some gas appliances, and challenges aligning the gas infrastructure replacement timelines with timelines for customers' own equipment turnover.[16]

However, National Grid has had three successful NPAs in rural upstate NY, where it identified 19 homes that are each directly served by a connection to gas transmission infrastructure, or "farm tap," that requires replacing gas regulator equipment. National Grid proposed covering the full cost of installing geothermal heating systems for each of these 19 homes, in lieu of investment in new regulators. Of these customers, five have expressed interest and three have moved forward with full electrification, with geothermal heating system installation complete.[17] Their gas service will be terminated, and any gas appliances replaced with electric appliances, paid for by the gas utility's program. Together, the electrification of these three customers will retire 586 feet of gas pipe and avoid the need for three new regulators.

NPAs for Avoiding Capacity Expansion Projects

National Grid has released three requests for proposals to date across six sites in the New York Cityand Long Island gas territories, seeking third-party vendors to offer NPA solutions to permanently reduce peak demand to help avoid future capacity investments planned to meet growing gas demand.[18] [19] The company is currently evaluating requests for proposal responses and considering the cost-effectiveness and deployment feasibility of proposed solutions.

Electrification, weatherization, and energy efficiency are among the solutions that National Grid and the third-party vendors have identified to permanently reduce peak demand. Unlike avoided replacement projects, these projects do not always require 100% of affected customers to participate. The number of participating customers needed to avoid the capacity expansion project will depend on the specific project and how much demand reduction is necessary.

NPAs for Avoiding New Customer Connections

When five or more potential new customers request to connect to National Grid's New York gas system, requiring the addition of more than 500 feet of gas main, National Grid has begun reaching out to these customers with information about NPA incentives for electrification in lieu of connection to the gas system. In these cases, the NPA incentives offered are equivalent to the value of the avoided pipeline installation. National Grid is considering expanding this offering to all potential new customers seeking to add more than 100 feet of gas main.

[16] To date, National Grid has reached customers via phone calls to inform them about NPA incentive opportunities for their property. In 2024, National Grid plans to expand its customer outreach to include email, postcards, and a website for customers to learn and engage further about NPA programs. National Grid is also considering resource requirements for door-to-door outreach.

[17] Of the five customers that initially expressed interest, one project didn't move forward as it was disqualified by the contractor and one customer opted out.

[18] KeySpan Energy Delivery New York (KEDNY) service territory.

[19] KeySpan Energy Delivery Long Island (KEDLI) service territory.

Integrated Energy Planning Analyses

In response to stakeholder and utility commission interest, National Grid electric and gas planning and asset management teams began in 2022 to jointly explore how to conduct IEP.

To better understand the methodology, assumptions, data and capabilities required to enable IEP, a team conducted an analysis that evaluated the electric network impacts of fully electrifying residential gas heating load in two Massachusetts towns with both National Grid electric and gas service. The team also identified segments of leak prone pipe that could be candidates for targeted electrification if customers could be fully electrified and the leak prone pipe segment decommissioned in lieu of replacement.

The preliminary analysis found that the cost of electric grid upgrades to support community-wide heating electrification for all residential customers in the two cities outweighed the costs of avoided gas infrastructure replacement. However, the analysis found some segments of leak-prone pipe that could be good NPA candidates, where the benefits of avoided gas infrastructure replacement outweighed the costs of electric grid upgrades to support the incremental electric demand.

The analysis also identified additional learnings. First, there is a wide range of potential peak load impacts from the electrification of heat depending on many factors, including the type, size and efficiency of the heat pump adopted, the energy efficiency of the premise, and whether electric resistance back-up heating is used. In addition, further analysis and sensitivities are needed to understand the implications of the electrification of transport, which could lead to higher cost of electric upgrades, as well as potential opportunities for load optimization or demand response that could help mitigate peak impacts.

The team also identified segments of leak prone pipe that could be candidates for targeted electrification if customers could be fully electrified and the leak prone pipe segment decommissioned in lieu of replacement.

The exercise also made it clear that new tools and resources would be needed to scale the analysis and to consider multiple scenarios and sensitivities, such as collaborative modeling between gas and electric planning systems and locational forecasting of customer propensity in heating technologies. Since that preliminary analysis, National Grid has explored and begun piloting new software tools that could enable more sophisticated and scalable IEP.

Other U.S. Case Studies: Utilities Advancing NPA Projects

Highlighted below are notable NPA efforts from three utilities in the U.S.: Pacific Gas & Electric, Con Edison, and Xcel Energy. As of early 2024, National Grid and RMI are also aware of ongoing NPA efforts at other New York utilities such as Rochester Gas and Electric and New York State Electric and Gas.[20]

Pacific Gas & Electric

Pacific Gas & Electric (PG&E) has successfully completed 88 targeted electrification projects, including decommissioning 22 miles of transmission pipe and converting 105 customers from gas. Each project has required high-touch customer outreach and in most cases, PG&E has offered to pay the full cost of customer conversion from gas service. PG&E has so far successfully executed projects affecting fewer than five customers at a time, reflecting the challenge of persuading larger clusters of customers to reach unanimous agreement on electrification. PG&E has also proposed a much larger project at California State University Monterey, where the university is the sole decision-maker for campus facilities.[21]

The requirement for voluntary participation from 100% of affected customers is an identified barrier to PG&E's pursuit of larger projects at scale. This requirement derives from the statutory 'obligation to serve,' which broadly obliges utilities to provide utility service upon request. In practice, this obligation prevents utilities from permanently ceasing service to a customer as part of a targeted electrification project so long as that customer wishes to continue to receive gas.[22] PG&E is considering support for legislative changes which could enable larger-scale targeted electrification initiatives.[23]

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PG&E has developed a Geospatial Electrification tool which the utility uses to identify candidate sites for NPAs across its system. PG&E has also provided a version of this gas asset analysis tool under NDA to some cities in its service territory to aid in their decarbonization planning. Additionally, the California Energy Commission has funded a "Targeted Building Electrification and Gas System Decommissioning Pilot Project" in Northern California which leverages PG&E's gas asset analysis tool to develop a framework to identify high-potential NPA projects. The project's interim report, "Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California," highlights questions essential to integrated energy planning, including what information about energy

[20] "Avangrid Subsidiaries NYSEG and RG&E Advance Their First Whole Home Electrification Project in New York," AP News, February 2024, https://apnews.com/press-release/business-wire/avangrid-inc-new-york-construction-and-engineering-government-programs-246e3fbad6da4b0aaca71e79aa82ace9.

[21] Pacific Gas and Electric, "Application of Pacific Gas and Electric Company (U 39 G) for Approval of Zonal Electrification Pilot Project and Request for Expedited Schedule," California Public Utilities Commission Application No. 22-08-003, August 10, 2022, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M496/K451/496451495.PDF.

[22] While exact language can vary, statute in most states includes a definition of utilities' obligation to serve customers as part of the public utilities code.

[23] For example, CA Senate Bill 527 did not pass in 2023 but would have allowed a limited number of pilot targeted electrification projects to proceed with less than 100% customer opt-in, subject to PUC oversight and approval. S.B. 23-527, (CA 2023), https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202320240SB527.

infrastructure and population demographics is needed to make near-term investment decisions that advance long-term utility, customer, and state policy goals.[24]

Con Edison

In November 2023, Con Edison released a Non-Pipes Alternatives Implementation Plan, detailing their NPA efforts to date. Con Edison operates two NPA programs: the Area Load Relief Program, which works to address capacity constraints across a broad area, and the Electric Advantage Program, which aims to avoid gas main replacements, such as those removing leak-prone pipe.

The Area Load Relief Program has one active project with expected efficiency investments beginning in 2024, which aims to achieve the necessary demand reduction by November 2025. Since its launch in 2023, the Electric Advantage Program has identified over 300 candidate projects, conducted customer outreach for 65 projects, and confirmed implementation plans for 3 projects that will convert a total of 5 customers from gas. Additional projects are anticipated to progress in 2024. The Electric Advantage Program has so far targeted only pipe segments serving fewer than 5 customers each. Con Edison's early experience emphasizes the importance of high-touch customer contact and face-to-face engagement for these projects.

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Xcel Energy

Under new gas planning rules established by the Colorado Public Utilities Commission in 2022, Xcel Colorado assessed NPA portfolios as potential alternatives to seven anticipated infrastructure investment projects. Of these, two NPA projects have been proposed for Commission approval.[25] One project impacts over 25,000 customers and aims to reduce peak gas demand by aggregating customer electrification to avoid the need for a gas capacity expansion project. The second project aims to avoid the replacement of high-risk mains and services, and thus requires full electrification of the 66 primarily commercial customers served by this infrastructure.

[24] Energy and Environmental Economics, Inc., Gridworks Organization, and East Bay Community Energy, "Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California," June 2023, https://gridworks.org/wp-content/uploads/2023/06/Evaluation-Framework-for-Strategic-Gas-Decommissioning-in-Northern-California-Interim-Report-for-CEC-PIR-20-009.pdf.

[25] Of the remaining five projects assessed, two were too far in the future (five years from filing, approximately six years from initial identification) to perform effective cost estimates and cost-benefit analyses, though these will continue to be assessed for NPAs in future filings. The remaining three projects will proceed with the gas infrastructure option, as the net economic benefit for the NPA option was less than the infrastructure option for one project, and the last two were required in-service by the 2024-2025 heating season. Public Service Company of Colorado, "PSCo Initial 2023-2028 Gas Infrastructure Plan, Attachments B.1-B.4 and B.6-B.8," Colorado Public Utilities Commission Proceeding No. 23M-0234G, May 18, 2023, https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_fil=G_804257&p_session_id=.

European Case Studies: Examples of Targeted Electrification and Clean Heat Planning

As of early 2024, National Grid and RMI are aware of several European countries actively advancing targeted electrification and clean heat planning. These examples focus on planned solutions at the municipal and neighborhood level.

Switzerland

Two cities in Switzerland – Zurich and Winterthur – have initiated plans to decommission some or all of their cities' natural gas distribution infrastructure. In both cases, utilities have informed residents in specific neighborhoods that gas service will be discontinued on a set timeline, typically 10 years in advance. The city of Basel is also planning neighborhood scale decommissioning for the whole city, with a targeted end date of 2037. To date, Zurich is the only city that has completed the decommissioning of segments of the gas system.

Zurich's gas utility, Energie360, initially pursued decommissioning in the North Zurich district based on the poor economics of maintaining the gas system in parallel with a district heating system, given that many customers had already converted from gas to district heat, and gas system utilization was low. Customer communications began in the early 2010s, and many of the affected customers have now seen gas service discontinued. Planning for additional decommissioning by neighborhood is currently underway, led by the City of Zurich in pursuit of GHG reduction goals. The city and utility are discussing plans for the city to compensate the utility for lost future earnings from gas sales, stemming from the next round of decommissioning projects.

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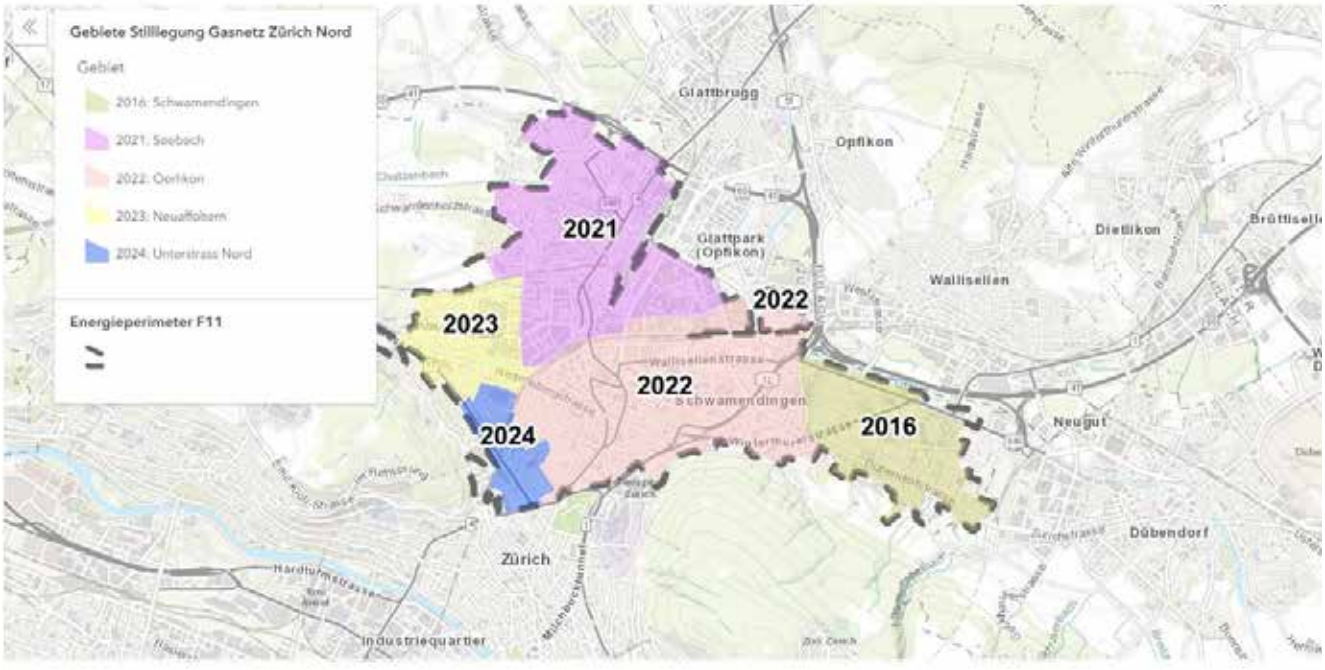
North Zurich neighborhood gas system decommissioning by year.[26]



[26] Energie 360, "Gas network closure in Zurich North," https://www.energie360.ch/de/kundenservice/gas-stilllegung

As part of the gas decommissioning process, the utility offers customers compensation based on the estimated remaining life of their gas equipment and the timeline between notification and gas shutoff. After first communicating a 5-year timeline for early projects, the utility extended the timeline to 10 years based on customer feedback.

In some cases, utilities have informed customers that district heating systems are being expanded to their neighborhoods as alternatives to gas. One identified challenge emerges when a customer's equipment reaches end-of-life before the district heating system is available. Parallels in the U.S. might include streets or neighborhoods where avoiding the gas infrastructure replacement requires additional electric investment that cannot be completed before the new heating systems are needed. This scenario will require special attention from implementers to ensure customers' energy needs continue to be met throughout the conversion.

Denmark

Denmark has a high penetration of district heating — 56% — whereas only 20% of households rely on gas for space heating.[27] The number of gas customers across Denmark is in decline, falling roughly 2% in 2021 and 8% in 2022 as both gas economics and European efforts to reduce reliance on Russian gas imports took hold. The state has a goal that no households are heated by gas after 2035. Industry and district heating are expected to continue receiving gas service but convert from fossil gas to biogas. As of fall 2023, there have been no examples yet of decommissioned gas pipe segments in Denmark.

The national gas distribution system operator, Evida, recently published a study of their system that screens for areas where decommissioning is feasible and would support the economic viability of the system.[28] Evida points to the fact that they must reduce their asset base to avoid significant rate increases as customer count falls. By their estimate, 28% of the subnetworks on the Danish gas system are not recovering revenue equal to their costs. Evida recommends these subnetworks as priorities for decommissioning but notes that shutting down a subnetwork currently requires gas customers to choose a different form of energy on their own initiative. Accordingly, the study highlights the need for legal changes to allow the utility to proactively designate gas subnetworks for decommissioning, with adequate customer notification and support.

Netherlands

The Netherlands has established a target that no households are heated with natural gas by 2050. Currently, 90% of buildings use gas for primary heating. Since 2018, most new construction has been prohibited from connecting to the gas distribution system. Measures to encourage electrification of existing buildings include a gradual reduction of taxes on electricity use and a corresponding increase in taxes on gas use, in addition to heat pump incentives.[29] Depreciation of existing gas infrastructure has been accelerated. In the past, customers disconnecting from the gas system were required to pay an "exit fee," but this cost is now socialized among all gas customers.

Currently, 90% of buildings in the Netherlands use gas for primary heating. Since 2018, most new construction has been prohibited from connecting to the gas distribution system.

[27] Katinka Johansen, Sven Werner, "Something is sustainable in the state of Denmark: A review of the Danish district heating sector," Renewable and Sustainable Energy Reviews, Volume 158, 2022, 112117, ISSN 1364-0321, https://doi.org/10.1016/j.rser.2022.112117.

[27] Evida, "Smart Conversion of Gas Consumption Must Transform the Gas System," June 27, 2023, https://evida.dk/media/4w2b1xdx/evidas-kortl%C3%A6gning-af-gasdistributionssystemet.pdf.

[29] Emma Koster, Katja Kruit, Marianne Teng, and Florian Hesselink, "The Natural Gas Phase-Out in the Netherlands," CE Delft, February 2022, https://cedelft.eu/wp-content/uploads/sites/2/2022/03/CE_Delft_210381_The_natural_gas_phase-out_in_the_Netherlands_DEF.pdf

Currently, municipalities are required to conduct local heat planning in consultation with utilities. However, when this planning process has identified neighborhoods for electrification and discontinued gas service, neither the municipality nor the utility has had a practical pathway to implement this plan.[30] Pending legislation would authorize municipalities to designate specific areas where gas service will be discontinued, with a minimum of eight years' notice.[31]

Germany

In Germany, municipalities are required to develop clean heat plans. Gas distribution systems in Germany are already "largely depreciated"—that is, the remaining net book value of existing assets is less than 20% of their initial cost. This is due in part to the advanced age of many gas assets currently in service.[32] A study by Agora Energiewende, a non-profit think tank, found that efficient planning of gas infrastructure could halve the total increase in gas bills through 2044, relative to the bill increases incurred in an unplanned scenario. While there are not yet specific policies or programs to plan and execute targeted electrification in Germany, there is an increasing focus on questions around gas transition, including emerging research and thought leadership on how to address new gas connections, decommissioning plans, and the potential role of accelerated depreciation.[33]

Austria

The City of Vienna published a climate neutral heating and cooling strategy statement on the building sector implications of the state's 2040 climate neutrality goal.[34] The policy explicitly centers on phasing out gas use. A current barrier to both utility gas system planning and municipal regulation of heating systems in existing buildings is the lack of policy clarity at the federal level. A potential federal law that would authorize municipalities to regulate existing buildings recently failed to reach consensus, and uncertainty about what level of government will hold the decision-making authority for decarbonizing the buildings sector has stalled action on this front.

[30] Ibid.
[31] Municipal Instruments Heat Transition Act, Dutch Parliament, 2023, https://www-tweedekamer-nl.translate.goog/kamerstukken/wetsvoorstellen/detail?cfg=wetsvoorsteldetails&qry=wetsvoorstel:36387&_x_tr_sl=auto&_x_tr_tl=en&_x_tr_hl=en&_x_tr_pto=wapp.
[32] Mareike Herrndorff, et. al., "A New Regulatory Framework for Natural Gas Distribution Networks," April 18, 2023, https://www-agora--energiewende-de.translate.goog/publikationen/ein-neuer-ordnungsrahmen-fuer-erdgasverteilnetze?_x_tr_sl=auto&_x_tr_tl=en&_x_tr_hl=en&_x_tr_pto=wapp.
[33] Bundesministerium für WIrstchaft und Klimaschutz. "Green Paper Transformation Gags-/Wasserstoff-Verteilernetze," 2024, https://www.bmwk.de/Redaktion/DE/Downloads/G/green-paper-transformation-gas-wasserstoff-verteilernetze.pdf?__blob=publicationFile&v=4
[34] City of Vienna, "Phasing Out Gas: Heating and Cooling Vienna 2040," 2023, https://www.wien.gv.at/stadtentwicklung/energie/pdf/phasing-out-gas.pdf.

Insights for Exploration in the U.S. Context

Across multiple jurisdictions with varied approaches to gas transition planning, these case studies encompass a significant body of experience. While examples of completed NPA projects in the U.S. are still limited, we develop several key insights below worth exploring further in the U.S. context.

1) NPA projects underway today reflect diverse energy policy goals and energy system characteristics across different jurisdictions.

In the U.S., low-cost domestic natural gas supply has led to widespread adoption of natural gas for heating and other purposes over many decades, with the associated expansion of gas distribution networks. Many stakeholders have recognized that continued gas system expansion is no longer consistent with climate policy; however, related policy and planning processes are still in their early stages. As described in the earlier sections, a handful of U.S. gas utilities have begun evaluating and pursuing NPAs as part of their gas planning processes.

In Europe, many jurisdictions have sought to reduce reliance on gas for some time, motivated by economic, geopolitical, and environmental concerns. As discussed earlier, recent developments such as the Russian invasion of Ukraine and related increases in the price of gas, put additional weight behind Europe's policy shift away from gas. At the national level, several jurisdictions have established policies to fully transition away from the use of natural gas. There are also a number of municipal planning processes underway in European cities to support more localized planning of future customer heating technologies and enable long-term infrastructure transitions.

Additional European jurisdictions, such as Germany, have further recognized the value of planning for the management of infrastructure transition costs. For jurisdictions or gas systems in the U.S. with significant undepreciated balances, there is an even higher incentive to act now to find ways to lower the overall costs of the transition to clean energy.

While it is important to recognize the successful and ongoing examples of NPAs and targeted electrification that have been explored in North America and Europe, it is also important to understand the distinctions among the jurisdictions where these projects are proceeding. Jurisdictions can vary significantly in geography, climate, customer composition, policy and regulatory preferences, the availability of other energy infrastructure, supply capacity, and the role that gas systems play in meeting today's energy demand. This diversity will necessarily shape the solutions that meet each jurisdiction's goals and needs.

2) NPA projects can identify value in cost savings on the gas system, emissions reduction, or other societal benefits.

Different jurisdictions and utilities have used varied terms and frameworks to distinguish among specific types of targeted electrification. For example, PG&E's efforts to date differentiate between 'targeted electrification', indicating projects motivated by cost savings on the gas system, and 'zonal electrification', indicating projects motivated by societal benefits, such as providing clean energy to disadvantaged communities or achieving significant greenhouse gas emissions reductions. In Europe, a common distinction is between heat planning, focused on the solutions that will provide clean heat to customers, and gas infrastructure planning, focused on the costs and timelines associated with maintaining, repairing, or retiring gas infrastructure. Broadly, these distinctions reflect the unique considerations for projects that are driven by infrastructure cost savings relative to those driven by other societal benefits.

Infrastructure-driven planning is characterized by a focus on economically driven projects that have a specific timeline – that is, where there is a quantifiable gas investment to be avoided. Common examples in the U.S. include areas of leak-prone pipe or pipe otherwise in need of safety remediation, gas assets at the end of their useful life, or infrastructure in need of capacity expansion to meet increased demand. Attractive NPA projects in lieu of such investments could accrue net savings to gas ratepayers, and early experience from the U.S. demonstrates that utilities have been able to identify such projects where the avoided cost is substantial and investments in NPA projects would be cost-effective.

Notably, certain types of infrastructure-driven projects allow for and require different approaches in order to avoid the anticipated gas system investment. For example, as discussed in the earlier case studies, solutions for capacity expansion projects can be targeted to a broad area and do not usually require 100% customer participation within that area, whereas leak-prone pipe in need of replacement would require all affected customers to adopt alternatives to natural gas service.

While capacity-related projects avoid this specific challenge, they face uncertainty in the permanence of the demand reduction as they cannot guarantee new loads won't appear in the future. Similar to replacement projects, capacity projects still require a minimum threshold of customer participation to ensure the gas investment can be avoided. This complicates the process of funding increased incentives for participating customers, as this funding is premised on avoiding the gas investment, which in turn is premised on a certain number of customers opting in, as well as the location and usage pattern of those customers relative to the capacity project.

Factors other than cost might motivate a utility, regulator, or municipality to prioritize an NPA even if the avoided gas investment alone is not sufficient to fully fund the project. 'Societally' driven projects thus comprise a broad category of projects not solely motivated by infrastructure costs. These could include projects motivated by their impact on reducing greenhouse gas emissions or projects motivated by providing benefits to disadvantaged communities. This category could also include specific communities that seek to exit the gas system regardless of the age of infrastructure serving them, such as through a municipal heat planning process driven by emissions reduction or other concerns. In the Swiss examples, the earliest projects were motivated primarily by cost savings for underutilized infrastructure, but more recent municipally driven projects are motivated by GHG reduction goals.

These categories can and do overlap. Some projects may have a quantifiable infrastructure investment to be avoided in a disadvantaged community, while other projects' avoided investment only covers a portion of the cost, with the remainder covered by funding intended for climate mitigation. The implications of these distinct categories impact how decision-makers might consider how to allocate costs for different projects, as well as how projects might be identified through energy or community planning processes.

3) Prioritization of NPA projects should weigh a broad set of criteria.

For utilities seeking to identify and pursue NPA opportunities within their existing capital or system planning processes (or via newer integrated energy planning processes), there are several key criteria to consider, many of which impact the overall economics of a given NPA project. These criteria include:

- **Gas asset risk and investment timeline:** For many projects, if the investment is needed urgently for safety or reliability, for instance in less than two years, it may not be feasible to implement an NPA before the need must be addressed. One notable exception is the success PG&E has found in executing small-scale (e.g., fewer than five impacted customers) projects in the range of 18-24 months. As illustrated in early experience in Zurich, longer

timelines are more important for larger, neighborhood-scale projects. Longer timelines of five or more years give stakeholders more time to design and implement appropriate solutions, particularly where NPAs and targeted electrification are nascent concepts. Timelines of up to five years may be workable but could be challenging for first-of-a-kind efforts impacting larger groups of customers.

- **Hydraulic feasibility:** Segments with a one-way flow or terminal branches can typically be removed without impacting the remaining system. Meanwhile, assets that provide reliability to other parts of the system may be difficult to retire. In some cases, the hydraulic impact of removing a segment of pipe can be mitigated through limited reinforcement elsewhere.
- **The outlook for local electric capacity, or headroom:** The simplest NPA projects will have ample local electric capacity that can accommodate added load from targeted electrification without costly electric upgrades. Other attractive projects could maintain peak demand below the local capacity threshold through demand-side measures such as load shifting or energy efficiency. Some NPA projects will require upgrades in electric capacity that could be costly. Even in these instances, it may be the case that organic load growth would have required capacity upgrades regardless of the NPA project, and it might not necessarily be appropriate to allocate all electric upgrade costs to the NPA project itself.
- **The types of customers:** Different customer types (residential, commercial, or industrial) or building types (single-family homes vs. large apartment buildings) may involve different levels of cost, difficulty, or NPA project scope.
- **The number of customers:** If each impacted customer must agree to participate for an NPA to proceed, projects with 1-5 customers may be more feasible than projects impacting a larger group, under current regulatory frameworks. Additionally, if the avoided infrastructure cost is divided across the impacted customers, each customer can receive a larger NPA incentive when the project affects fewer customers.
- **The presence of community support:** Partnership with community-based organizations, local governments, or interested individuals can facilitate productive customer engagement. A local government with high climate ambition or additional motivations to reduce the presence of gas infrastructure in their community may be able to provide additional support through data sharing and staff capacity.
- **Customer propensity:** The likelihood of customers to adopt electric technologies and opt to participate in an NPA project could be an indicator of project success, as NPA projects are dependent on voluntary participation under the current regulatory framework. Indicators of customer propensity could include building stock and energy usage data (such as the age and energy intensity of buildings), customer participation in utility programs, awareness and adoption of heat pumps, and other demographic data.
- **Equity:** Equity criteria, such as location in a disadvantaged community and enrollment in bill discount rates, are also important to consider in site prioritization. Cost effectiveness and customer propensity criteria may be at odds with equity criteria, so it is important to assess these criteria holistically to balance a utility's cost and equity goals.

The relative weight of each criterion may vary depending on the goals and authority of the decision-maker, whether the utility, the state utility commission, or a municipality.

In prioritizing projects and crafting implementation plans, utilities will need to weigh gas system, electric system, and customers' system considerations and economics together. One approach seen in Winterthur mapped the city according to the type of clean heating solution each neighborhood would transition to; these maps index predominantly on customer density to determine suitability for extension of existing network heating or construction of new heat networks. While district heating is much less prevalent in the U.S., thermal energy networks are increasingly of interest to utilities, regulators, and stakeholders, particularly in urban areas with colder climates. Where appropriate, NPA planning could

assess feasibility for thermal energy networks, as these provide an opportunity for utility business model evolution and can mitigate peak electric network infrastructure requirements and costs, if deployed at scale.

4) NPA projects can be funded from a series of different sources while protecting ratepayers' long-term affordability.

NPA projects can involve multiple distinct categories of cost, including:

- front-of meter gas system costs, including the cost of decommissioning the gas asset,
- front-of-meter electric system costs (e.g., distribution capacity upgrades),
- behind-the-meter costs (e.g., the cost of electrification retrofits), and
- programmatic or administrative costs.

In the context of long-term declining gas demand, NPA projects should aim to mitigate upward rate pressure on customers remaining on the gas system. Not only will managing system costs improve customer equity and long-term affordability, but it will also contribute to utilities' long-term cost recovery and financial health via reasonable rates.

Some existing regulatory mechanisms, such as accelerated depreciation, are available to aid with financially sustainable and equitable cost recovery. However, additional policy mechanisms may be needed to help manage gas transition costs, including the potential flow of funding across the electric and gas customer bases, as demonstrated by the Québec gas and electric utilities discussed on page 23.

Cost-effectiveness evaluations are a key method of determining the amount of funding appropriate for ratepayers to pay into a targeted electrification or NPA program. Due to the broad set of benefits these projects provide, these tests may include societal costs and benefits, including carbon reduction benefits. Appropriately accounting for the societal and customer value of the investment efficiencies enabled through IEP and NPAs will require updating cost-effectiveness tests as these solutions scale.

Below we lay out the major potential sources of funding for NPA projects, with the rationale for using each.

Federal and state funding (taxpayers)

Where federal or state funding is available, these sources should be pursued to maximize ratepayer savings whenever possible. For example, the Infrastructure Investment and Jobs Act and the Inflation Reduction Act make available significant funding for programs that help to reduce the costs of NPA projects. Many states including Massachusetts and New York also offer rebates and incentives for energy efficiency upgrades, heat pumps, and more efficient appliances. To the extent targeted electrification initiatives are a priority for a given jurisdiction, legislators may appropriate funds specifically to support these projects.

Gas ratepayers

NPA projects present an opportunity to avoid costs on the gas system, thereby achieving savings for gas ratepayers. This forms the primary rationale for recovering NPA funding from gas ratepayers. These projects also provide a direct opportunity to reduce GHG emissions. Because NPAs are premised on the ability to avoid a future investment in gas infrastructure, there is a strong justification for gas ratepayers to provide funding for these projects. At the same time, it may be appropriate to limit gas ratepayer funding to some threshold below the full avoided cost, so that some avoided spending can be returned as savings for gas ratepayers.

In certain cases, paying more than the avoided infrastructure cost may be justified based on project benefits, though the allocation of these costs between gas and electric customers should be determined by regulators. These benefits could include the innovation value of early project demonstrations, quantified GHG benefits, or support for income-qualified customers' participation in targeted electrification and NPA projects. In the long term, particularly as rate pressures on a declining gas customer base increase, decision-makers may wish to reconsider whether it continues to make sense to seek NPA funding from gas ratepayers.

Electric ratepayers

Funding from electric customers is premised on the benefits that NPA projects provide via load growth and additional future revenue on the electric system. Electric ratepayers could also be responsible for incentives for equipment upgrades that may be needed, after any state and federal energy efficiency incentives are exhausted. One model of funding could draw a "bright line" between the two rate bases, allocating electric ratepayer funding only to associated costs on the electric system, and gas ratepayer funding only to costs on the gas system. This model's simplicity may be particularly attractive for early or pilot projects. Alternately, regulators could determine what amount of funding is justified on either side of the "bright line," while allowing for the potential combination of funding for any remaining costs.

Local taxpayer funding

Local funding from a county, city, or town may be a particularly relevant resource where the municipality is conducting clean heat planning that might pursue more NPA projects than could be funded through traditional pathways.

Individual customers

Most customers will bear some costs within the home, as they would during normal equipment replacement. Offering a sufficient timeline from initial notice to gas decommissioning could allow a reasonable period for homeowners and building owners to plan for proactive equipment replacement in lieu of short term or emergency replacements.

In the Swiss case studies identified above, customers are typically given 10 years' notice and offered supportive incentives and programming but are responsible for costs in excess of the incentives they receive. For low- and moderate-income customers, additional support for equipment replacement and supplemental upgrades such as energy efficiency will be needed.

5) Integrated gas and electric network planning offers an opportunity to achieve net-zero goals as cost-effectively and equitably as possible.

An orderly transition to net-zero emissions requires gas and electric coordination and collaboration on system planning, as well as involvement of customers and communities in decision-making. Coordinated planning offers several opportunities to ensure affordability and reliability, including:

- Prudently building out the electric system in the right locations at the right time to prepare for conversion of fossil fuel-based heating (including delivered fuels as well as natural gas) to electric heating;
- Making calculated decisions about where on the gas system to prioritize investment (e.g. leak-prone pipe repair or replacement) and/or planning to decommission sections of the gas network in favor of electric heating or thermal networks; and
- Leveraging energy efficiency and load control to help optimize demand and avoid the highest-cost infrastructure scenarios.

An orderly transition to net-zero emissions requires gas and electric coordination and collaboration on system planning, as well as involvement of customers and communities in decision-making.

Coordination between and within utilities to optimize long-range investment plans is critical to ensure a cost-effective energy transition for all customers.

Optimized investment of this kind requires a significant, long-term exchange of geographically specific data between planning teams within or across utilities. For example, coordinated planning could ensure electric capacity is available or built out in time to support NPA projects. However, a process for information exchange between utilities at this level of specificity does not yet exist. While some utilities serving both gas and electricity have voluntarily embarked on intra-utility integration of their gas and electric teams, the scalability of these efforts is constrained by limited levels of territorial overlap, especially in the Northeast U.S. Regulatory action is thus needed to enable data sharing and decision making between utilities in a more comprehensive way. Absent regulatory support, it is unlikely that integrated energy planning will achieve the scale needed to realize cross-system savings.

Regulatory support is needed to invest in new tools and capabilities that enable integrated energy planning to achieve a cost-optimized transition.

Key tools could include software that translates geographic gas demand scenarios into impacts on electric system load, and vice versa. These gas and electric load scenarios would then inform geographically specific distribution planning for both systems, and aid in the identification of high priority, or most cost-effective, NPA projects. These tools should also be used to generate versions of distribution system maps that could be shared with municipal or local government planners to support local clean heat planning.

PG&E has already developed an asset screening tool, featuring an integrated mapping of gas and electric systems with customer data. This tool has aided in early research on potential NPA frameworks for California. Indeed, such an integrated system mapping and planning tool empowers the utility and partners to identify potential projects along multiple prioritization criteria. PG&E's mapping tool has also helped cities gain insight for localized decarbonization planning.

Targeted electrification and NPA pilots should leverage integrated planning to inform the development of regulatory frameworks for deploying these solutions at scale.

Regulators should encourage pilots to test innovative approaches to scaling NPAs, including through novel cost recovery and allocation structures. Pilots could also be used to test deployment under alternate structures of the utilities' obligation to serve, though this model may require legislative authorization. Where customers' gas and electric providers differ, pilots should also seek to inform new protocols for cross-utility coordination. Development of these pilots will enable testing of new data-sharing, planning, and cost-recovery structures across utilities.

Québec Example of Cross-Utility Funding

Énergir and Hydro-Québec, respectively the primary gas and electric utilities serving Québec, have signed an agreement for a joint decarbonization strategy. This strategy, approved by the regulatory authority, centers on partial (70%) electrification of building heating systems with gas backup. The strategy includes compensation payments from the electric utility to the gas utility based on avoided electric peak capacity investments enabled by maintaining gas backup. Participating gas customers are estimated to see modest annual bill savings, while the gas utility anticipates preserving a substantial share of distribution revenues despite a significant reduction in gas throughout.

This approach provides an early example of integrated energy planning, including the concept of funding flowing between gas and electric rate bases contingent on the value that each system contributes through decarbonization-focused programs. In the near term, funding across rate bases could be applicable to thermal energy networks where capital investments cannot be reasonably recovered from thermal network customers alone. In the longer term, regulators may consider models of cross-rate base funding that account for the value each system provides the other, in service of broader policy goals such as the reduction of GHG emissions.

6) Utility and municipality partnership may be a key element of NPA projects and localized integrated energy planning.

As seen in the European case studies highlighted above, local energy planning achieves the level of granularity needed to plan for and meet local needs. Policymakers and regulators should find ways to empower local energy planning that identifies a long-term portfolio of heat solutions for a community or municipality. It will be important for utilities to partner with municipal governments conducting local energy planning, both to share system maps and to provide technical partnership in municipal decision-making based on system data. Potential benefits of local energy planning include the opportunity for residents and local leaders to design and champion locally tailored solutions.

The early examples of successful European targeted electrification projects come from the Swiss cities in which municipal government has become more involved in making community-specific heating transition decisions. Pending new legislation, communities in the Netherlands are poised for similar progress, having already coordinated between municipal governments and utilities on community-wide heating plans.

Applying a similar model in the U.S. could entail supporting municipalities to partner with the utilities that serve them to conduct clean heat planning, including identifying segments of the gas network for NPA and thermal heating projects. This approach could allow municipalities with ambitious climate policies to pursue NPAs at a faster pace than others, and to reflect local priorities in identifying projects.

This kind of partnership can be effective if it produces proposed NPA projects rooted both in utility analysis and community priorities. To make it effective in the U.S., utilities, municipalities, regulators, and policymakers will need to take several new actions:

- Utilities will need to develop improved tools and capabilities for evaluating NPA opportunities at the local level, building on data across the gas system, electric system, and their customer base, as described above.
- Utilities and municipal staff will need to learn how to conduct this collaborative planning most effectively. Utilities generally have little precedent for such detailed planning with local government, and cities may lack the staff capacity or expertise to partner fully.
- Regulators may need to provide guidance to streamline such planning and make it consistent across their state. Regulators can also set clear expectations for how the outputs of this planning will be evaluated – for instance, how they will evaluate proposed NPA projects resulting from utility-municipal joint planning.
- Regulators must provide clear guidance on cost allocation and cost recovery, recognizing the need for a clear framework to advance proposed NPA projects, while also protecting ratepayers outside first mover communities and ensuring less well-resourced communities are not burdened by early NPA projects.
- Policymakers will need to give clear direction regarding how the utility's obligation to serve will be treated for projects resulting from joint utility-municipal planning, to ensure promising projects can advance, as described further below.
- In cases where a community is served by separate gas and electric utilities, this planning will be more complex. In this case, new guidance will be needed regarding how data will be shared across both systems and the responsibilities of each utility. New policy direction may be needed, including for the case in which an investor-owned utility provides one service, and a municipal or cooperative utility provides another.

7) Individual customer persuasion to reach 100% participation is not a scalable NPA approach for avoided replacement projects.

Several U.S. utilities are currently pursuing individual customer persuasion to implement NPAs, with notable but limited success. In order for avoided replacement NPA projects to be successful, 100% of affected customers need to transition all gas heating equipment and appliances, including water heaters and stoves, to electric and transition off of the gas

system. As discussed, it is very difficult to get all customers to participate and disconnect from the gas system in projects with more than 5 customers.

Early experience makes clear that, under a voluntary model, any one customer can derail a potential project that is otherwise economically attractive and well-received by other customers, thereby limiting the prospects for this approach.

These approaches continue to have value, and new customer engagement strategies may expand success. However, it is unlikely they will readily scale to be a substantial portion of projects that could be attractive on economic and climate terms. There may be more scalable success in the near term pursuing this approach in projects not requiring 100% participation, such as capacity expansion projects.

8) Policy change will be needed to evolve the utility business model and obligation to serve, while still retaining the opportunity for cost recovery in a transition away from the use of gas.

In many jurisdictions, gas utilities are obligated by statute or regulation to connect new customers upon request and/or to continue providing service to existing customers (i.e. indefinitely). Such obligations have implications for targeted electrification projects. Utilities' obligation to connect new gas customers upon request will require the construction of new gas infrastructure regardless of whether the expansion is economically viable. Utilities' obligation to continue serving gas to existing customers poses a different challenge – that even where an NPA solution is economically attractive, if even one customer wishes to continue receiving gas service, the utility may still be required to install new infrastructure to maintain service.

This policy challenge requires designing a new process to enable projects driven by community needs or system economics rather than individual customer opt-in. Addressing this challenge will entail new and substantial policy shifts that also ensure reliable and affordable energy for customers.

This policy challenge requires designing a new process to enable projects driven by community needs or system economics rather than individual customer opt-in. Addressing this challenge will entail new and substantial policy shifts that also ensure reliable and affordable energy for customers.

In many cases in the U.S., legislative change is needed at the state level to enable regulators to work with stakeholders to develop a new paradigm for equitable access to essential energy services. The simplest change would remove the statutory obligation for utilities to continue serving gas to existing customers and empower regulators to enable or establish alternative plans or programs whereby customers are still provided with affordable and equitable access to energy.

Another model, as illustrated by the Swiss and Dutch case studies, would empower motivated municipalities to conduct heat planning that includes the retirement of gas infrastructure. In the Swiss case, community willingness to be an 'early adopter' of clean heat and infrastructure planning enabled cities like Zurich and Winterthur to proactively designate which neighborhoods would transition from the gas system on specific timelines. This approach also enabled these cities to plan the expansion of existing and construction of new district heating systems to align with geographically specific heat infrastructure plans. Such an approach would similarly require utility regulators to play an active role in project approval and the establishment of guardrails to ensure that reliability is maintained, excessive costs are not put onto ratepayers, and utilities have the opportunity to recover prudent investments in gas infrastructure even as NPA projects scale.

State regulators have a critical role in overseeing changes to the provision of utility service.

In the U.S., relevant authorities for infrastructure investment and service provision are provided by statute to public utility commissions. These commissions are charged with setting utility rates and policy in accordance with the regulatory compact that provides utilities with an opportunity to earn a reasonable return on investment in exchange for providing safe and reliable service at reasonable cost to all customers who request it.

Utility regulators have a critical role to play in implementing any changes to the utilities' obligation to serve and advancing NPAs.

As such, state regulators have a critical role to play in overseeing infrastructure planning and changes to the provision of utility service. The regulatory process to establish guardrails in any model of a reformed obligation to serve could include determinations of the minimum years of notice given to customers who would no longer receive gas, guidance on incentives and customer compensation, design of programs to support customers in transitioning behind-the-meter equipment, and preconditions tying the termination of service to municipal heat plans or other forms of municipal support. Regardless of the method of reform, utility regulators have a critical role to play in implementing any changes to the utilities' obligation to serve and advancing NPAs. Regulatory guidance is necessary to require the identification and analysis of NPAs, shape cost-effectiveness assessments, direct deeper analyses of utilities' investments, update rate mechanisms and depreciation methodologies that provide the opportunity to recover prudent investments, create data-sharing protocols across utilities with overlapping territory and with interested municipalities, conduct robust stakeholder processes, and set requirements for both broad and targeted customer education.

Conclusion

The insights laid out in this paper are a starting point for further exploration in the U.S. context. Our hope in presenting this work is for the findings to serve as a jumping-off point for future work across the country.

Below are some suggested starting points for decision-makers and stakeholders seeking to advance this work.

- Regulators should develop specific guidance to clarify the path to identify, propose, receive approval for, implement, and recover costs for NPAs in their state.
- Utilities should advance efforts to pursue the most achievable NPAs under existing frameworks (e.g., projects serving 1-5 customers, under the 100% persuasion model, and projects to avoid capacity expansions).
- Decision-makers should find ways to encourage increased utility-municipal engagement, data sharing, and cooperation for integrated energy planning in support of jurisdictional climate policy goals.
- Regulators should also support utilities' development of integrated system mapping tools to facilitate cross-utility coordinated planning and cooperation with interested municipalities.
- Stakeholders should develop an understanding of the ways utilities' obligation to serve may need to evolve, and what guardrails are necessary, in their state.
- Regulators should update rate mechanisms and depreciation methodologies that address the opportunity to recover prudent investments and protect future ratepayers, in light of anticipated changes in long-run gas system utilization.

Additional References

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Exhibit___(CLCPA-4)

Gas Demand Response EAM Methodology

Gas Demand Response EAM Methodology

Table 1: Actual performance during gas DR events in NMPC, winters 2022-23 & 2023-24, by event type

Gas day beginning	Winter	Program	Event Type	Event Hours	Dth/Hr Reduction
12/12/2022	2022-23	Load Shedding	Test	3	164
2/3/2023	2022-23	Load Shedding	Actual	8	132
11/28/23	2023-34	Load Shedding	Test	3	196
1/17/24	2023-34	Load Shedding	Test	3	237
1/17/24	2023-34	BYOT	Test	4	38

Table 2: Actual performance during gas DR events in NMPC, winters 2022-23 & 2023-24, aggregated by gas day

Gas day beginning	Winter	Dth/Hr Reduction
12/12/2022	2022-23	164
2/3/2023	2022-23	132
11/28/23	2023-34	196
1/17/24	2023-34	275

Table 3: Maximum dth/hr reduction among each winter's gas DR events, winters 2022-23 through 2024-25

Winter	Dth/Hr Reduction	Notes
2022-23	164	*actual value*
2023-24	275	*actual value*
2024-25	329	*placeholder value (to be updated with actual after close of winter 2024-25 season)*

Chart 1: Baseline value
(based on winters 2022-22 through 2024-25 with placeholder value for winter 2024-25)

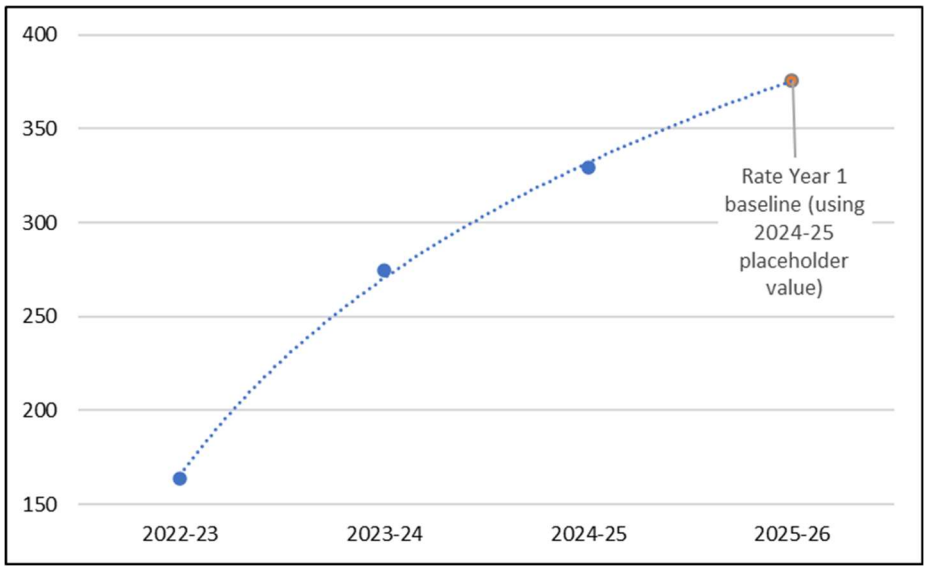

Table 4: Baseline and target values (using 2024-25 placeholder value; to be updated after close of winter season)

Level	% above baseline	Rate Year 1 value (dth/hr)
Baseline	n/a	376
Minimum	4%	391
Midpoint	8%	406
Maximum	28%	481

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Exhibit___(CLCPA-5)

Earnings Adjustment Mechanism ("EAM") Targets

Electric Earning Adjustment Mechanism Targets

System Efficiency EAM

	a	b	c	d	e	f	g	h
	Metric	Measure		CY 2025	CY 2026	CY 2027	CY 2028	Term
1	Electric Demand Response	Operational Available MW above Baseline	Min	1.4x	1.4x	1.4x	1.4x	-
2			Mid	1.8x	1.8x	1.8x	1.8x	-
3			Max	2.2x	2.2x	2.2x	2.2x	-
4	DER Utilization	Total Annual MWh above the Baseline	Min	250,355	261,240	283,010	293,895	1,088,500
5			Mid	325,462	339,613	367,914	382,064	1,415,053
6			Max	488,193	509,419	551,870	573,096	2,122,578
7	Managed EV Charging:: Residential	% Increase in the Number of Participating Customer Charging >80% of their Load During Off-Peak Hours	Min	5%	5%	5%	5%	-
8			Mid	15%	15%	15%	15%	-
9			Max	25%	25%	25%	25%	-
10	Managed EV Charging: Fleet	% Improvement in the Share of Chargers Charging Off-Peak	Min	5%	5%	5%	5%	-
11			Mid	15%	15%	15%	15%	-
12			Max	25%	25%	25%	25%	-
13	Disadvantage Community Demand Response	% Improvement in the Annual DR DAC Participation	Min	10%	10%	10%	10%	-
14			Mid	15%	15%	15%	15%	-
15			Max	20%	20%	20%	20%	-

Beneficial Electrification EAM

	Metric	Measure		CY 2025	CY 2026	CY 2027	CY 2028	Term
16	Transportation Electrification - MHD	MW of Make-Ready Infrastructure Installed per Year	Min	7	14	20	25	66
17			Mid	10.5	21	30	37.5	99
18			Max	14	28	40	50	132

Gas Earning Adjustment Mechanism Targets

	a	b	c	d	e	f	g	h
	System Efficiency EAM							
	Metric	Measure		CY 2025	CY 2026	CY 2027	CY 2028	Term
1	Gas Demand Response	Dth Reduction above Baseline	Min	4%	4%	4%	4%	-
2			Mid	8%	8%	8%	8%	-
3			Max	28%	28%	28%	28%	-

Exhibit___(CLCPA-6)

EAM Basis Points and Incentives

Electric Earning Adjustment Mechanism Basis Points & Incentives

	a	b	c	d	e	f	g	h	i	j	k	l

System Efficiency EAM

			Basis Points					$ Million				
	Metric		CY 2025	CY 2026	CY 2027	CY 2028	Term	CY 2025	CY 2026	CY 2027	CY 2028	Term
1	Electric Demand Response	Min	3.0	3.0	3.0	3.0	12.0	$ 1.8	$ 2.2	$ 2.6	$ 2.9	9.5
2		Mid	6.0	6.0	6.0	6.0	24.0	$ 3.6	$ 4.4	$ 5.2	$ 5.7	18.9
3		Max	12.0	12.0	12.0	12.0	48.0	$ 7.2	$ 8.7	$ 10.4	$ 11.5	37.8
4	DER Utilization	Min	2.0	2.0	2.0	2.0	8.0	$ 1.2	$ 1.5	$ 1.7	$ 1.9	6.3
5		Mid	8.0	8.0	8.0	8.0	32.0	$ 4.8	$ 5.8	$ 6.9	$ 7.6	25.2
6		Max	16.0	16.0	16.0	16.0	64.0	$ 9.6	$ 11.6	$ 13.9	$ 15.3	50.4
7	Managed EV Charging -- Residential	Min	2.0	2.0	2.0	2.0	8.0	$ 1.2	$ 1.5	$ 1.7	$ 1.9	6.3
8		Mid	4.0	4.0	4.0	4.0	16.0	$ 2.4	$ 2.9	$ 3.5	$ 3.8	12.6
9		Max	6.0	6.0	6.0	6.0	24.0	$ 3.6	$ 4.4	$ 5.2	$ 5.7	18.9
10	Managed EV Charging -- Fleet	Min	2.0	2.0	2.0	2.0	8.0	$ 1.2	$ 1.5	$ 1.7	$ 1.9	6.3
11		Mid	4.0	4.0	4.0	4.0	16.0	$ 2.4	$ 2.9	$ 3.5	$ 3.8	12.6
12		Max	6.0	6.0	6.0	6.0	24.0	$ 3.6	$ 4.4	$ 5.2	$ 5.7	18.9
13	Disadvantage Community Demand Response	Min	1.0	1.0	1.0	1.0	4.0	$ 0.6	$ 0.7	$ 0.9	$ 1.0	3.2
14		Mid	3.0	3.0	3.0	3.0	12.0	$ 1.8	$ 2.2	$ 2.6	$ 2.9	9.5
15		Max	5.0	5.0	5.0	5.0	20.0	$ 3.0	$ 3.6	$ 4.3	$ 4.8	15.8

Beneficial Electrification EAM

			Basis Points					$ Million				
	Metric		CY 2025	CY 2026	CY 2027	CY 2028	Term	CY 2025	CY 2026	CY 2027	CY 2028	Term
16	MHD Transportation Electrification	Min	3.0	3.0	3.0	3.0	12.0	$ 1.8	$ 2.2	$ 2.6	$ 2.9	9.5
17		Mid	6.0	6.0	6.0	6.0	24.0	$ 3.6	$ 4.4	$ 5.2	$ 5.7	18.9
18		Max	12.0	12.0	12.0	12.0	48.0	$ 7.2	$ 8.7	$ 10.4	$ 11.5	37.8

			Basis Points				$ Million			
			CY 2025	CY 2026	CY 2027	CY 2028	CY 2025	CY 2026	CY 2027	CY 2028
19	Electric EAM Total	Min	13.0	13.0	13.0	13.0	$ 7.8	$ 9.5	$ 11.3	$ 12.4
20		Mid	31.0	31.0	31.0	31.0	$ 18.7	$ 22.6	$ 26.9	$ 29.6
21		Max	57.0	57.0	57.0	57.0	$ 34.3	$ 41.5	$ 49.4	$ 54.4

Gas Earning Adjustment Mechanism Basis Points & Incentives

System Efficiency EAM

	a	b	c	d	e	f	g	h	i	j	k	l
			Basis Points					$ Million				
	Metric		CY 2025	CY 2026	CY 2027	CY 2028	Term	CY 2025	CY 2026	CY 2027	CY 2028	Term
1	Gas Demand Response	Min	1.0	1.0	1.0	1.0	4.0	$ 0.14	$ 0.16	$ 0.18	$ 0.19	$ 0.67
2		Mid	3.0	3.0	3.0	3.0	12.0	$ 0.43	$ 0.48	$ 0.53	$ 0.56	$ 2.00
3		Max	5.0	5.0	5.0	5.0	20.0	$ 0.71	$ 0.80	$ 0.89	$ 0.93	$ 3.33

			Basis Points				$ Million			
			CY 2025	CY 2026	CY 2027	CY 2028	CY 2025	CY 2026	CY 2027	CY 2028
4	Gas EAM Total	Min	1.0	1.0	1.0	1.0	$ 0.14	$ 0.16	$ 0.18	$ 0.19
5		Mid	3.0	3.0	3.0	3.0	$ 0.43	$ 0.48	$ 0.53	$ 0.56
6		Max	5.0	5.0	5.0	5.0	$ 0.71	$ 0.80	$ 0.89	$ 0.93

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Exhibit___(CLCPA-7)

Summary of EAM Net Benefits

Summary of Electric EAM Net Benefits

	a	b	c	d	e	f
1	**Summary of EAM Net**	**Portfolio Net Benefits**	**4 Year EAM Incentive Value**	**Savings to Customers**	**EAM Incentive**	**Savings to Customers**
2		**NPV**	**NPV**	**NPV**	**%**	**%**
3	**Minimum**	$1,587.7	$35.0	$1,552.6	2%	98%
4	**Midpoint**	$2,058.9	$83.5	$1,975.4	4%	96%
5	**Maximum**	$2,905.9	$153.6	$2,752.3	5%	95%

Benefits			
Total (NPV $M)	**Minimum**	**Midpoint**	**Maximum**
Avoided AGCC	**$ 337.1**	**$ 380.9**	**$ 433.0**
Avoided MW (Demand Response)	$ 58.8	$ 61.3	$ 63.8
Avoided MW (DER Utilization)	$ 276.4	$ 317.3	$ 366.1
Avoided MW (Managed EV Charging Resi+Fleet)	$ 1.9	$ 2.3	$ 3.0
Avoided Transmission	**$ 19.0**	**$ 42.2**	**$ 44.7**
Avoided MW (Demand Response)	$ 16.8	$ 39.5	$ 41.1
Avoided MW (Managed EV Charging Resi+Fleet)	$ 2.2	$ 2.7	$ 3.6
Avoided Distribution	**$ 63.8**	**$ 68.8**	**$ 75.9**
Avoided MW (Demand Response)	$ 51.3	$ 53.5	$ 55.8
Avoided MW (Managed EV Charging Resi+Fleet)	$ 12.4	$ 15.3	$ 20.1
Avoided MWh	**$ 675.4**	**$ 899.1**	**$ 1,348.6**
Avoided MWh (DER Utilization)	$ 675.4	$ 899.1	$ 1,348.6
Avoided CO_2	**$ 496.7**	**$ 664.2**	**$ 991.8**
Avoided CO_2 (DER Utilization)	$ 478.5	$ 636.9	$ 955.4
Avoided CO_2 (Transportation Electrification -- MHD)	$ 18.2	$ 27.3	$ 36.5
Avoided PM 2.5	**$ 2.1**	**$ 3.1**	**$ 4.1**
Avoided PM 2.5 (Transportation Electrification -- MHD)	$ 2.1	$ 3.1	$ 4.1
Avoided Non-Electric Fuel	**$ 118.5**	**$ 177.7**	**$ 237.0**
Avoided Fuel (Transportation Electrification -- MHD)	$ 118.5	$ 177.7	$ 237.0
TOTAL BENEFITS	**$ 1,712.6**	**$ 2,236.0**	**$ 3,135.0**

Costs			
Total (NPV $M)	**Minimum**	**Midpoint**	**Maximum**
Implementation Costs	**$ 124.9**	**$ 177.1**	**$ 229.1**
Demand Response	$ 24.3	$ 27.8	$ 30.2
DER Utilization	-	$ -	$ -
Managed EV Charging Resi+Fleet	$ 6.2	$ 7.9	$ 10.2
MHD Transportation Electrification	$ 94.3	$ 141.5	$ 188.7
TOTAL COSTS	**$ 124.9**	**$ 177.1**	**$ 229.1**

	Minimum	**Midpoint**	**Maximum**
NET BENEFITS (NPV $M)	**$ 1,587.7**	**$ 2,058.9**	**$ 2,905.9**

	Minimum	**Midpoint**	**Maximum**
Total Benefits ($M)			
Demand Response	$ 127.0	$ 154.3	$ 160.8
DER Utilization	$ 1,430.3	$ 1,853.3	$ 2,670.1
EV Managed Charging (Resi + Fleet)	$ 16.5	$ 20.3	$ 26.7
Transportation Electrification -- MHD	$ 138.8	$ 208.1	$ 277.5
Total Costs ($M)			
Demand Response	$ 24.3	$ 27.8	$ 30.2
DER Utilization	-	$ -	$ -
EV Managed Charging (Resi + Fleet)	$ 6.2	$ 7.9	$ 10.2
Transportation Electrification -- MHD	$ 94.3	$ 141.5	$ 188.7
Total Net Benefits ($M)			
Demand Response	$ 102.6	$ 126.5	$ 130.6
DER Utilization	$ 1,430.3	$ 1,853.3	$ 2,670.1
EV Managed Charging (Resi + Fleet)	$ 10.3	$ 12.5	$ 16.4
Transportation Electrification -- MHD	$ 44.4	$ 66.6	$ 88.9

Summary of Gas EAM Net Benefits

	a	b	c	d	e	f
1	Summary of EAM Net Benefits	Portfolio Net Benefits	4-year EAM Incentive Value	Savings to Customers	EAM Incentive	Savings to Customers
2		NPV ($M)	NPV ($M)	NPV ($M)	%	%
3	Minimum	$12.7	$0.6	$12.1	4%	96%
4	Midpoint	$13.2	$1.7	$11.5	13%	87%
5	Maximum	$15.6	$2.8	$12.8	18%	82%

6	**Benefits (NPV $M)**			
7	**Benefits (Gas EAM Metric)**	**Minimum**	**Midpoint**	**Maximum**
8	**Avoided Dth**	**$ 18.0**	**$ 18.7**	**$ 22.1**
11	Avoided Dth (Gas Demand Response)	$ 18.0	$ 18.7	$ 22.1
15	**Avoided CO_2**	**$ 0.1**	**$ 0.1**	**$ 0.1**
18	Avoided CO_2 (Gas Demand Response)	$ 0.1	$ 0.1	$ 0.1
22	TOTAL BENEFITS (NPV $M)	$ 18.0	$ 18.7	$ 22.2
23				
24	**Costs (NPV $M)**			
25	**Costs (Gas EAM Metric)**	**Minimum**	**Midpoint**	**Maximum**
26	**Implementation Costs**	**$ 5.3**	**$ 5.5**	**$ 6.6**
29	Gas Demand Response	$ 5.3	$ 5.5	$ 6.6
33	TOTAL COSTS (NPV $M)	$ 5.3	$ 5.5	$ 6.6
34		**Minimum**	**Midpoint**	**Maximum**
35	**NET BENEFITS (NPV $M)**	**$ 12.7**	**$ 13.2**	**$ 15.6**

Testimony of Climate Leadership and Community Protection Act Panel

Exhibit___(CLCPA-8)

Electric Demand Response EAM Net Benefits

Electric Demand Response EAM Net Benefits

	a	b	c	d	e	f	g	h	i
1		**Baseline**		**CY2024**	**CY2025**	**CY2026**	**CY2027**	**CY2028**	**Total NPV**
2		Assumes 4.4% growth rate across all years							
3			1 Ngrid C&I	311	324	339	354	369	
4			2 Ngrid Resi	29	30	32	33	35	
5			3 SCR	571	597	623	651	679	
6		Assumed hours of resource availability	33						
7		Assumed percent of C&I customers served at distribution level	17%						
8									
9		**Min (Assumes baseline + Min all years)**		**CY2024**	**CY2025**	**CY2026**	**CY2027**	**CY2028**	**Total NPV**
10			1 Ngrid C&I	311	330	350	372	395	
11			2 Ngrid Resi	29	31	33	35	37	
12			3 SCR	571	607	644	684	727	
13									
14	*Per NY BCA Handbook*	Avoided Generation Capacity Costs ($/MW)			$ 26.4	$ 23.9	$ 23.4	$ 24.0	
15	*Per NY BCA Handbook*	Avoided Transmission Costs ($/MW)			$ 27.0	$ 27.5	$ 28.0	$ 28.6	
16	*Per NY BCA Handbook*	Avoided Distribution Costs ($/MW)			$ 151.6	$ 154.6	$ 157.7	$ 160.8	
17	*Per NY BCA Handbook*	Net Marginal Damage Cost of CO2 ($/MWh)			$ 31.0	$ 31.8	$ 32.6	$ 33.4	
18	*Avoided MW (Resi + C/I) × Avoided Transmission Cost per MW*	Avoided MW Transmission Costs			$ 9.7	$ 10.5	$ 11.4	$ 12.4	$ 37.8
19	*(Avoided MW Resi + Avoided MW C/I*.17) × Avoided Distribution Cost per MW*	Avoided MW Distribution Costs			$ 13.2	$ 14.3	$ 15.5	$ 16.8	$ 51.3
20	*(Avoided MW Resi + Avoided MW SCR) × AGCC per MW*	Avoided MW Generation Capacity			$ 16.8	$ 16.2	$ 16.8	$ 18.3	$ 58.8
21	*Available MWh*Cost of CO2 ($/MWh)*	Avoided CO2 Costs			$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.9
22									
23		**Total Benefits**			**$ 40.0**	**$ 41.3**	**$ 44.0**	**$ 47.7**	**$ 148.9**
24									
25		Labor			$ 0.4	$ 0.4	$ 0.5	$ 0.5	$ 1.6
26		Implementation			$ 0.8	$ 0.8	$ 0.9	$ 0.9	$ 2.9
27		Incentives			$ 5.3	$ 5.6	$ 5.9	$ 6.2	$ 19.9
28									
29		**Total Costs**			**$ 6.6**	**$ 6.9**	**$ 7.2**	**$ 7.6**	**$ 24.3**
30									
31		**Net Benefit (Min)**			**$ 33.5**	**$ 34.4**	**$ 36.7**	**$ 40.1**	**$ 124.6**
32									
33		**Mid (Assumes baseline + Mid all years)**		**CY2024**	**2025**	**2026**	**2027**	**2028**	**Total NPV**
34			1 Ngrid C&I	311	335	362	391	422	
35			2 Ngrid Resi	29	31	34	37	40	
36			3 SCR	571	617	666	719	776	
37									
38	*Per NY BCA Handbook*	Avoided Generation Capacity Costs ($/MW)			$ 26.4	$ 23.9	$ 23.4	$ 24.0	
39	*Per NY BCA Handbook*	Avoided Transmission Costs ($/MW)			$ 27.0	$ 27.5	$ 28.0	$ 28.6	
40	*Per NY BCA Handbook*	Avoided Distribution Costs ($/MW)			$ 151.6	$ 154.6	$ 157.7	$ 160.8	
41	*Per NY BCA Handbook*	Net Marginal Damage Cost of CO2 ($/MWh)			$ 31.0	$ 31.8	$ 32.6	$ 33.4	
42	*Avoided MW (Resi + C/I) × Avoided Transmission Cost per MW*	Avoided MW Transmission Costs			$ 9.9	$ 10.9	$ 12.0	$ 13.2	$ 39.5
43	*(Avoided MW Resi + Avoided MW C/I*.17) × Avoided Distribution Cost per MW*	Avoided MW Distribution Costs			$ 13.4	$ 14.8	$ 16.3	$ 17.9	$ 53.5
44	*(Avoided MW Resi + Avoided MW SCR) × AGCC per MW*	Avoided MW Generation Capacity			$ 17.1	$ 16.7	$ 17.7	$ 19.6	$ 61.3
45	*Available MWh*Cost of CO2 ($/Mwh)*	Avoided CO2 Costs			$ 0.4	$ 0.4	$ 0.5	$ 0.5	$ 1.6
46									
47		**Total Benefits**			**$ 40.8**	**$ 42.8**	**$ 46.4**	**$ 51.2**	**$ 155.9**
48									
49									
50		Labor			$ 0.4	$ 0.4	$ 0.5	$ 0.5	$ 1.6
51		Implementation			$ 0.8	$ 0.8	$ 0.9	$ 0.9	$ 2.9
52		Incentives			$ 5.6	$ 6.4	$ 7.4	$ 7.8	$ 23.3
53									
54		**Total Costs (Mid)**			**$ 6.8**	**$ 7.7**	**$ 8.7**	**$ 9.2**	**$ 27.8**
55									
56		**Net Benefits (Mid)**			**$ 34.0**	**$ 35.1**	**$ 37.7**	**$ 42.0**	**$ 128.1**
57									

58		**Max (Assumes baseline + Max all years)**		**CY2024**		**2025**		**2026**		**2027**		**2028**	**Total NPV**
59			1 Ngrid C&I	311		341		374		411		450	
60			2 Ngrid Resi	29		32		35		39		42	
61			3 SCR	571		627		688		755		829	
62													
63	*Per NY BCA Handbook*	Avoided Generation Capacity Costs ($/MW)			$	26.4	$	23.9	$	23.4	$	24.0	
64	*Per NY BCA Handbook*	Avoided Transmission Costs ($/MW)			$	27.0	$	27.5	$	28.0	$	28.6	
65	*Per NY BCA Handbook*	Avoided Distribution Costs ($/MW)			$	151.6	$	154.6	$	157.7	$	160.8	
66	*Per NY BCA Handbook*	Net Marginal Damage Cost of CO2 ($/MWh)			$	31.0	$	31.8	$	32.6	$	33.4	
67	*Avoided MW (Resi + C/I) × Avoided Transmission Cost per MW*	Avoided MW Transmission Costs			$	10.0	$	11.2	$	12.6	$	14.1	$ 41.1
68	*(Avoided MW Resi + Avoided MW C/I*.17) × Avoided Distribution Cost per MW*	Avoided MW Distribution Costs			$	13.6	$	15.3	$	17.1	$	19.1	$ 55.8
69	*(Avoided MW Resi + Avoided MW SCR) × AGCC per MW*	Avoided MW Generation Capacity			$	17.4	$	17.3	$	18.5	$	20.9	$ 63.8
70	*Available MWh*Cost of CO2 ($/Mwh)*	Avoided CO2 Costs			$	0.4	$	0.5	$	0.5	$	0.6	$ 1.7
71													
72		**Total Benefits**			**$**	**41.5**	**$**	**44.3**	**$**	**48.7**	**$**	**54.7**	**$ 162.4**
73													
74		Labor			$	0.42	$	0.44	$	0.46		$0.49	$2
75		Implementation			$	0.79	$	0.83	$	0.87		$0.91	$3
76		Incentives			$	5.83	$	7.00	$	8.40		$8.82	$26
77													
78		**Total Costs (Max)**			**$**	**7.0**	**$**	**8.3**	**$**	**9.7**	**$**	**10.2**	**$ 30.2**
79													
80		**Net Benefits (Max)**			**$**	**34.5**	**$**	**36.0**	**$**	**39.0**	**$**	**44.4**	**$ 132.2**

Testimony of Climate Leadership and Community Protection Act Panel

Exhibit___(CLCPA-9)

Gas Demand Response EAM Net Benefits

Gas Demand Response EAM Net Benefits

	a	b	c	d	e	f
1	**Demand Response Reduction Targets (Dth)***	**Winter 2025-26**	**Winter 2026-27**	**Winter 2027-28**	**Winter 2028-29**	
2	Minimum	391	426	454	479	
3	Midpoint	406	442	472	497	
4	Maximum	481	524	559	589	
5						
6	**Constant assumptions**			**Source**		
7	Events called per year	3				
8	Average event duration (hrs)	8				
9	% reductions derived from Fuel Switching	40%	*based on approximate amounts provided during winter 2022-23 emergency and actual events*			
10	% of Participation from Capacity Exempt Customers	75%				
11	Natural gas emission rate (lb CO2/MMBtu)	116.7	*EIA.gov*			
12	Fuel oil emission rate (lb CO2/MMBtu)	163.5				
13	Replacement ratio of fuel oil for natural gas (gallons/dth)	7.2				
14	MMBtu per gallon, #2 fuel oil	0.1385	*EIA.gov*			
15	Implementation costs per hourly dth saved (includes program administration, incentives, and EM&V)	$3,372	*Preliminary 2023-24 Implementation Costs*			
16	Discount rate	7.01%				
17						

18	**Variable assumptions**	**Winter 2025-26**	**Winter 2026-27**	**Winter 2027-28**	**Winter 2028-29**	**Source**
19	Estimated annualized marginal capacity cost of gas ($/dth/hr)					*Exhibit__(GSP-9), CNG Project Peak Day Capacity Costs row, multiplied by 20 to convert to an hourly rate*
20	Marginal cost of Distribution ($/dth/hr)	$ 8,359	$ 8,359	$ 8,359	$ 8,359	*Exhibit ___(NMG-24) Marginal Class Study, Annual Demand Cost per Design Day dth, multiplied by 20 to convert to an hourly rate*
21	Peaking services - commodity cost ($/dth)	$ 3.90	$ 3.90	$ 3.90	$ 3.90	*Exhibit__(GSP-8)*
22	Social cost of carbon	$ 60.09	$ 62.54	$ 65.06	$ 67.66	*Per NYS "E-Value"*
23	Fuel oil cost ($/MMBtu)	$ 24.73	$ 25.35	$ 26.01	$ 26.76	*EIA AEO 2022, Table 3.2, Middle Atlantic Region, Reference Case*
24						

25	**Benefits at Minimum**	**Winter 2025-26**	**Winter 2026-27**	**Winter 2027-28**	**Winter 2028-29**	**NPV**
26	Supply and Distribution Capacity savings ($M)	$ 4.73	$ 5.16	$ 5.51	$ 5.80	
27	Avoided annual dth	9,373	10,217	10,906	11,489	
28	Peaking commodity savings ($M)	$ 0.04	$ 0.04	$ 0.04	$ 0.04	
29	*Total avoided dth savings ($M)*	*$ 4.77*	*$ 5.20*	*$ 5.55*	*$ 5.85*	*$17.98*
30	Fuel oil savings (MMBtu/yr)	(3,739)	(4,075)	(4,350)	(4,583)	
31	Peak gas CO2 savings (tons CO2)	496	540	577	608	
32	Fuel oil CO2 savings (tons CO2)	(277)	(302)	(322)	(340)	
33	Total CO2 savings (tons CO2)	219	238	254	268	
34	*Total avoided CO2 savings ($M)*	*$ 0.01*	*$ 0.01*	*$ 0.02*	*$ 0.02*	*$0.05*
35	**Total benefits ($M)**	**$ 4.78**	**$ 5.21**	**$ 5.57**	**$ 5.86**	**$18.04**
36						

37	**Costs at Minimum**	**Winter 2025-26**	**Winter 2026-27**	**Winter 2027-28**	**Winter 2028-29**	**NPV**
38	Total fuel oil commodity costs ($M)	$ 0.09	$ 0.10	$ 0.11	$ 0.12	
39	Implementation costs ($M)	$ 1.32	$ 1.44	$ 1.53	$ 1.61	
40	**Total costs ($M)**	**$ 1.41**	**$ 1.54**	**$ 1.65**	**$ 1.74**	**$5.33**
41						

42		**Winter 2025-26**	**Winter 2026-27**	**Winter 2027-28**	**Winter 2028-29**	**NPV**
43	**Net benefits at minimum ($M)**	**$ 3.37**	**$ 3.67**	**$ 3.92**	**$ 4.13**	**$12.71**
44	**BCA**	**3.39**	**3.39**	**3.38**	**3.38**	**3.38**
45						

46	**Benefits at Midpoint**	**Winter 2025-26**	**Winter 2026-27**	**Winter 2027-28**	**Winter 2028-29**	**NPV**
47	Supply and Distribution Capacity savings ($M)	$ 4.91	$ 5.36	$ 5.72	$ 6.02	
48	Avoided annual dth	9,733	10,610	11,326	11,931	
49	Peaking commodity savings ($M)	$ 0.04	$ 0.04	$ 0.04	$ 0.05	
50	*Total avoided dth savings ($M)*	*$ 4.95*	*$ 5.40*	*$ 5.76*	*$ 6.07*	*$18.67*
51	Fuel oil savings (MMBtu/yr)	(3,882)	(4,232)	(4,518)	(4,759)	

Peak gas CO2 savings (tons CO2)	515	561	599	631	
Fuel oil CO2 savings (tons CO2)	(288)	(314)	(335)	(353)	
Total CO2 savings (tons CO2)	227	248	264	278	
Total avoided CO2 savings ($M)	*$ 0.01*	*$ 0.02*	*$ 0.02*	*$ 0.02*	*$0.05*
Total benefits ($M)	**$ 4.97**	**$ 5.41**	**$ 5.78**	**$ 6.09**	**$18.73**

Costs at Midpoint	**Winter 2025-26**	**Winter 2026-27**	**Winter 2027-28**	**Winter 2028-29**	**NPV**
Total fuel oil commodity costs ($M)	$ 0.10	$ 0.11	$ 0.12	$ 0.13	
Implementation costs ($M)	$ 1.37	$ 1.49	$ 1.59	$ 1.68	
Total costs ($M)	**$ 1.46**	**$ 1.60**	**$ 1.71**	**$ 1.80**	**$5.53**

	Winter 2025-26	**Winter 2026-27**	**Winter 2027-28**	**Winter 2028-29**	**NPV**
Net benefits at midpoint ($M)	**$ 3.50**	**$ 3.82**	**$ 4.07**	**$ 4.29**	**$13.20**
BCA	**3.39**	**3.39**	**3.38**	**3.38**	**3.38**

Benefits at Maximum	**Winter 2025-26**	**Winter 2026-27**	**Winter 2027-28**	**Winter 2028-29**	**NPV**
Supply and Distribution Capacity savings ($M)	$ 5.82	$ 6.35	$ 6.78	$ 7.14	
Avoided annual dth	11,536	12,574	13,423	14,141	
Peaking commodity savings ($M)	$ 0.04	$ 0.05	$ 0.05	$ 0.06	
Total avoided dth savings ($M)	*$ 5.87*	*$ 6.40*	*$ 6.83*	*$ 7.19*	*$22.13*
Fuel oil savings (MMBtu/yr)	(4,601)	(5,016)	(5,354)	(5,640)	
Peak gas CO2 savings (tons CO2)	610	665	710	748	
Fuel oil CO2 savings (tons CO2)	(341)	(372)	(397)	(418)	
Total CO2 savings (tons CO2)	269	293	313	330	
Total avoided CO2 savings ($M)	*$ 0.02*	*$ 0.02*	*$ 0.02*	*$ 0.02*	*$0.06*
Total benefits ($M)	**$ 5.89**	**$ 6.42**	**$ 6.85**	**$ 7.22**	**$22.20**

Costs at Maximum	**Winter 2025-26**	**Winter 2026-27**	**Winter 2027-28**	**Winter 2028-29**	**NPV**
Total fuel oil commodity costs ($M)	$ 0.11	$ 0.13	$ 0.14	$ 0.15	
Implementation costs ($M)	$ 1.62	$ 1.77	$ 1.89	$ 1.99	
Total costs ($M)	**$ 1.73**	**$ 1.89**	**$ 2.03**	**$ 2.14**	**$6.56**

	Winter 2025-26	**Winter 2026-27**	**Winter 2027-28**	**Winter 2028-29**	**NPV**
Net benefits at maximum ($M)	**$ 4.15**	**$ 4.52**	**$ 4.82**	**$ 5.08**	**$15.64**
BCA	**3.39**	**3.39**	**3.38**	**3.38**	**3.38**

* Minimum targets based on logarithmic regression derived from historical values for winters 2022-23 and 2023-24 and placeholder value of 329 (120% of winter 2023-24 achievement) for winter 2024-25

Testimony of Climate Leadership and Community Protection Act Panel

Exhibit___(CLCPA-10)

DER Utilization EAM Net Benefits

DER Utilization Net Benefits

Assumptions

Escalation	2.5%
Solar coincidence	36%

At Minimum

	CY 2025	CY 2026	CY 2027	CY 2028
Targets (MW)	284	297	321	334

Benefits - Minimum	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	NPV
Estimated Capacity Interconnected																													
MW Installed - 2025	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284	284			
Estimated Capacity Interconnected																													
MW Installed - 2026		297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297	297			
Estimated Capacity Interconnected																													
MW Installed - 2027			321	321	321	321	321	321	321	321	321	321	321	321	321	321	321	321	321	321	321	321	321	321	321	321	321		
Estimated Capacity Interconnected																													
MW Installed - 2028				334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334	334		
Total Estimated Capacity Interconnected	**284**	**581**	**902**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**1,236**	**952**	**655**	**334**	
Total MW Installed																													
Assume 0.5% Degradation Annually	100%	100%	99%	99%	98%	98%	97%	97%	96%	96%	95%	95%	94%	94%	93%	93%	92%	92%	91%	91%	90%	90%	90%	89%	89%	88%	88%	87%	
Solar Panel Degradation Rate (y0, y1, y2, etc)																													
MWh × Degradation =	250,355	249,103	247,858	246,618	245,385	244,158	242,938	241,723	240,514	239,312	238,115	236,925	235,740	234,561	233,388	232,222	231,060	229,905	228,756	227,612	226,474	225,341	224,215	223,094	221,978				
Avoided MWh -- 2025 Installs																													
MW Installed × Solar Coincidence × Deeradation =	102	102	101	101	101	100	100	99	99	98	98	97	97	96	96	95	95	94	94	93	93	92	92	92	91	91			
Avoided MW -- 2025 Installs																													
MWh × Degradation =		261,240	259,934	258,634	257,341	256,054	254,774	253,500	252,233	250,971	249,717	248,468	247,226	245,990	244,760	243,536	242,318	241,107	239,901	238,701	237,508	236,320	235,139	233,963	232,793	231,629			
Avoided MW -- 2026 Installs		107	106	106	106	105	105	104	104	103	103	102	102	101	101	100	100	99	99	98	98	97	97	96	96	95	95		
MW Installed × Solar Coincidence × Deeradation =																													
MWh × Degradation =			283,010	281,595	280,187	278,786	277,392	276,005	274,625	273,252	271,886	270,526	269,174	267,828	266,489	265,156	263,830	262,511	261,199	259,893	258,593	257,300	256,014	254,734	253,460	252,193	250,932		
Avoided MW -- 2027 Installs			116	115	114	114	113	113	112	112	111	110	110	109	109	108	108	107	107	106	106	105	105	104	103	103	102		
MW Installed × 8.760 Hours × Canacity Factor × Deeradation =				267.178	265.842	264.513	263.190	261.874	260.565	259.262	257.966	256.676	255.393	254.116	252.845	251.581	250.323	249.071	247.826	246.587	245.354	244.127	242.907	241.692	240.484	239.281	238.085	236.894	
Avoided MWh -- 2028 Installs																													
MW Installed × Solar Coincidence × Deeradation =				118	118	117	117	116	116	115	114	114	113	113	112	112	111	110	110	109	109	108	108	107	107	106	106	105	
Avoided MW -- 2028 Installs																													
Per NY BCA Handbook	$ 26.42	$ 23.93	$ 23.36	$ 23.97	$ 25.88	$ 28.78	$ 31.92	$ 38.55	$ 46.35	$ 52.43	$ 58.85	$ 65.51	$ 71.66	$ 78.14	$ 80.10	$ 82.10	$ 84.15	$ 86.25	$ 88.41	$ 90.62	$ 92.89	$ 95.21	$ 97.59	$ 100.03	$ 102.53	$ 105.09	$ 107.72	$ 110.41		
Avoided Generation Capacity Costs ($/MW)																													
Per NY BCA Handbook	$ 41.00	$ 41.54	$ 45.54	$ 46.52	$ 48.05	$ 49.51	$ 50.89	$ 51.75	$ 52.57	$ 54.43	$ 55.41	$ 58.21	$ 59.67	$ 61.16	$ 62.69	$ 64.26	$ 65.86	$ 67.51	$ 69.20	$ 70.93	$ 72.70	$ 74.52	$ 76.38	$ 78.29	$ 80.25	$ 82.25	$ 84.31	$ 86.42		
Avoided Locational-Based Marginal Price ($/MWh)																													
Per NY BCA Handbook	$ 31.03	$ 31.81	$ 32.60	$ 33.42	$ 34.25	$ 35.11	$ 35.99	$ 36.88	$ 37.81	$ 38.75	$ 39.72	$ 40.71	$ 41.73	$ 42.78	$ 43.84	$ 44.94	$ 46.06	$ 47.22	$ 48.40	$ 49.61	$ 50.85	$ 52.12	$ 53.42	$ 54.76	$ 56.12	$ 57.53	$ 58.97	$ 60.44		
Net Marginal Damage Cost of CO2 ($/MWh)																													
Avoided MW × AGCC $/MW =	$ 2.70	$ 2.43	$ 2.36	$ 2.41	$ 2.59	$ 2.87	$ 3.17	$ 3.81	$ 4.55	$ 5.12	$ 5.72	$ 6.34	$ 6.90	$ 7.49	$ 7.63	$ 7.79	$ 7.94	$ 8.10	$ 8.26	$ 8.42	$ 8.59	$ 8.76	$ 8.94	$ 9.11	$ 9.29	$ -	$ -	$ -	$ -	
Avoided MW -- 2025 Installs																													
Avoided MWh × LBMP $/MWh =	$ 10.27	$ 10.35	$ 11.29	$ 11.47	$ 11.79	$ 12.09	$ 12.36	$ 12.51	$ 12.64	$ 13.03	$ 13.19	$ 13.79	$ 14.07	$ 14.35	$ 14.63	$ 14.92	$ 15.22	$ 15.52	$ 15.83	$ 16.14	$ 16.46	$ 16.79	$ 17.13	$ 17.47	$ 17.81	$ -	$ -	$ -	$166.74	
Avoided Energy Savings ($M) -- 2025 Installs																													
Avoided MW × Cost of CO2 $/MW =	$ 7.77	$ 7.92	$ 8.08	$ 8.24	$ 8.40	$ 8.57	$ 8.74	$ 8.92	$ 9.09	$ 9.27	$ 9.46	$ 9.65	$ 9.84	$ 10.03	$ 10.23	$ 10.44	$ 10.64	$ 10.86	$ 11.07	$ 11.29	$ 11.52	$ 11.74	$ 11.98	$ 12.22	$ 12.46	$ -	$ -	$ -	$118.84	
Avoided CO2 Savings ($M) -- 2025 Installs																													
Avoided MW Savings + Avoided Energy Savings + Avoided CO2 Savings =	**$ 20.74**	**$ 20.70**	**$ 21.73**	**$ 22.13**	**$ 22.79**	**$ 23.53**	**$ 24.27**	**$ 25.22**	**$ 26.29**	**$ 27.42**	**$ 28.38**	**$ 29.78**	**$ 30.80**	**$ 31.86**	**$ 32.50**	**$ 33.14**	**$ 33.80**	**$ 34.47**	**$ 35.16**	**$ 35.86**	**$ 36.57**	**$ 37.30**	**$ 38.04**	**$ 38.79**	**$ 39.57**	**$ -**	**$ -**	**$ -**	**$349.37**	
Total Benefits ($M) -- 2025 Installs																													
Avoided MW × AGCC $/MW =	$ -	$ 2.56	$ 2.49	$ 2.54	$ 2.73	$ 3.02	$ 3.33	$ 4.00	$ 4.78	$ 5.39	$ 6.01	$ 6.66	$ 7.25	$ 7.87	$ 8.02	$ 8.18	$ 8.35	$ 8.51	$ 8.68	$ 8.85	$ 9.03	$ 9.21	$ 9.39	$ 9.58	$ 9.77	$ 9.96	$ -	$ -	$66.52	
Avoided MW -- 2026 Installs																													
Avoided MWh × LBMP $/MWh =	$ -	$ 10.85	$ 11.84	$ 12.03	$ 12.37	$ 12.68	$ 12.97	$ 13.12	$ 13.26	$ 13.66	$ 13.84	$ 14.46	$ 14.75	$ 15.04	$ 15.34	$ 15.65	$ 15.96	$ 16.28	$ 16.60	$ 16.93	$ 17.27	$ 17.61	$ 17.96	$ 18.32	$ 18.68	$ 19.05	$ -	$ -	$168.82	
Avoided Energy Savings ($M) -- 2026 Installs																													
Avoided MW × Cost of CO2 $/MW =	$ -	$ 8.31	$ 8.47	$ 8.64	$ 8.81	$ 8.99	$ 9.17	$ 9.35	$ 9.54	$ 9.73	$ 9.92	$ 10.12	$ 10.32	$ 10.52	$ 10.73	$ 10.94	$ 11.16	$ 11.38	$ 11.61	$ 11.84	$ 12.08	$ 12.32	$ 12.56	$ 12.81	$ 13.07	$ 13.33	$ -	$ -	$119.82	
Avoided CO2 Savings ($M) -- 2026 Installs																													
Avoided MW Savings + Avoided Energy Savings + Avoided CO2 Savings =	**$ -**	**$ 21.72**	**$ 22.80**	**$ 23.21**	**$ 23.91**	**$ 24.68**	**$ 25.46**	**$ 26.47**	**$ 27.58**	**$ 28.77**	**$ 29.77**	**$ 31.24**	**$ 32.32**	**$ 33.43**	**$ 34.10**	**$ 34.78**	**$ 35.47**	**$ 36.17**	**$ 36.89**	**$ 37.62**	**$ 38.37**	**$ 39.13**	**$ 39.91**	**$ 40.71**	**$ 41.51**	**$ 42.34**	**$ -**	**$ -**	**$355.16**	
Total Benefits ($M) -- 2026 Installs																													
Avoided MW × AGCC $/MW =	$ -	$ -	$ 2.70	$ 2.76	$ 2.96	$ 3.28	$ 3.62	$ 4.35	$ 5.20	$ 5.85	$ 6.53	$ 7.24	$ 7.88	$ 8.55	$ 8.72	$ 8.89	$ 9.07	$ 9.25	$ 9.43	$ 9.62	$ 9.81	$ 10.00	$ 10.20	$ 10.40	$ 10.61	$ 10.82	$ 11.04	$ -	$72.03	
Avoided MW -- 2027 Installs																													
Avoided MWh × LBMP $/MWh =	$ -	$ -	$ 12.89	$ 13.10	$ 13.46	$ 13.80	$ 14.12	$ 14.28	$ 14.44	$ 14.87	$ 15.07	$ 15.75	$ 16.06	$ 16.38	$ 16.71	$ 17.04	$ 17.38	$ 17.72	$ 18.07	$ 18.43	$ 18.80	$ 19.17	$ 19.55	$ 19.94	$ 20.34	$ 20.74	$ 21.16	$ -	$177.61	
Avoided Energy Savings ($M) -- 2027 Installs																													
Avoided MW × Cost of CO2 $/MW =	$ -	$ -	$ 9.23	$ 9.41	$ 9.60	$ 9.79	$ 9.98	$ 10.18	$ 10.38	$ 10.59	$ 10.80	$ 11.01	$ 11.23	$ 11.46	$ 11.68	$ 11.92	$ 12.15	$ 12.39	$ 12.64	$ 12.89	$ 13.15	$ 13.41	$ 13.68	$ 13.95	$ 14.23	$ 14.51	$ 14.80	$ -	$125.42	
Avoided CO2 Savings ($M) -- 2027 Installs																													
Avoided MW Savings + Avoided Energy Savings + Avoided CO2 Savings =	**$ -**	**$ -**	**$ 24.82**	**$ 25.26**	**$ 26.02**	**$ 26.87**	**$ 27.72**	**$ 28.81**	**$ 30.02**	**$ 31.31**	**$ 32.40**	**$ 34.00**	**$ 35.17**	**$ 36.38**	**$ 37.11**	**$ 37.84**	**$ 38.59**	**$ 39.36**	**$ 40.14**	**$ 40.94**	**$ 41.76**	**$ 42.59**	**$ 43.43**	**$ 44.30**	**$ 45.18**	**$ 46.07**	**$ 46.99**	**$ -**	**$375.86**	
Total Benefits ($M) -- 2027 Installs																													
Avoided MW × AGCC $/MW =	$ -	$ -	$ -	$ 2.84	$ 3.05	$ 3.38	$ 3.72	$ 4.48	$ 5.35	$ 6.03	$ 6.73	$ 7.45	$ 8.11	$ 8.80	$ 8.98	$ 9.16	$ 9.34	$ 9.52	$ 9.71	$ 9.91	$ 10.10	$ 10.30	$ 10.51	$ 10.72	$ 10.93	$ 11.15	$ 11.37	$ 11.60	$74.09	
Avoided MW -- 2028 Installs																													
Avoided MWh × LBMP $/MWh =	$ -	$ -	$ -	$ 12.43	$ 12.77	$ 13.10	$ 13.40	$ 13.55	$ 13.70	$ 14.11	$ 14.29	$ 14.94	$ 15.24	$ 15.54	$ 15.85	$ 16.17	$ 16.49	$ 16.81	$ 17.15	$ 17.49	$ 17.84	$ 18.19	$ 18.55	$ 18.92	$ 19.30	$ 19.68	$ 20.07	$ 20.47	$162.19	
Avoided Energy Savings ($M) -- 2028 Installs																													
Avoided MW × Cost of CO2 $/MW =	$ -	$ -	$ -	$ 8.93	$ 9.11	$ 9.29	$ 9.47	$ 9.66	$ 9.85	$ 10.05	$ 10.25	$ 10.45	$ 10.66	$ 10.87	$ 11.09	$ 11.31	$ 11.53	$ 11.76	$ 11.99	$ 12.23	$ 12.48	$ 12.72	$ 12.98	$ 13.23	$ 13.50	$ 13.77	$ 14.04	$ 14.32	$114.41	
Avoided CO2 Savings ($M) -- 2028 Installs																													
Avoided MW Savings + Avoided Energy Savings + Avoided CO2 Savings =	**$ -**	**$ -**	**$ -**	**$ 24.20**	**$ 24.93**	**$ 25.76**	**$ 26.59**	**$ 27.69**	**$ 28.90**	**$ 30.18**	**$ 31.27**	**$ 32.85**	**$ 34.01**	**$ 35.21**	**$ 35.91**	**$ 36.63**	**$ 37.36**	**$ 38.10**	**$ 38.86**	**$ 39.63**	**$ 40.42**	**$ 41.22**	**$ 42.04**	**$ 42.87**	**$ 43.73**	**$ 44.59**	**$ 45.48**	**$ 46.38**	**$ 358.69**	
Total Benefits ($M) -- 2028 Installs																													
Avoided MW Savings ($M) -- All Years	$ 2.70	$ 4.99	$ 7.55	$ 10.55	$ 11.33	$ 12.54	$ 13.84	$ 16.63	$ 19.89	$ 22.38	$ 25.00	$ 27.69	$ 30.14	$ 32.70	$ 33.35	$ 34.01	$ 34.69	$ 35.38	$ 36.08	$ 36.80	$ 37.53	$ 38.28	$ 39.04	$ 39.81	$ 40.60	$ 31.93	$ 22.41	$ 11.60	$276.44	
Avoided Energy Savings ($M) -- All Years	$ 10.27	$ 21.20	$ 36.02	$ 49.03	$ 50.39	$ 51.66	$ 52.84	$ 53.47	$ 54.04	$ 55.67	$ 56.39	$ 58.95	$ 60.12	$ 61.31	$ 62.53	$ 63.77	$ 65.04	$ 66.33	$ 67.65	$ 69.00	$ 70.37	$ 71.77	$ 73.19	$ 74.65	$ 76.13	$ 59.48	$ 41.23	$ 20.47	$675.36	
Avoided CO2 Savings ($M) -- All Years	$ 7.77	$ 16.23	$ 25.78	$ 35.22	$ 35.92	$ 36.64	$ 37.36	$ 38.11	$ 38.86	$ 39.64	$ 40.42	$ 41.23	$ 42.05	$ 42.88	$ 43.73	$ 44.60	$ 45.49	$ 46.39	$ 47.32	$ 48.26	$ 49.22	$ 50.19	$ 51.19	$ 52.21	$ 53.25	$ 41.60	$ 28.84	$ 14.32	$478.48	
Total Benefits ($M) -- All Years	**$ 20.74**	**$ 42.42**	**$ 69.35**	**$ 94.80**	**$ 97.65**	**$ 100.83**	**$ 104.04**	**$ 108.20**	**$ 112.79**	**$ 117.69**	**$ 121.82**	**$ 127.86**	**$ 132.30**	**$ 136.89**	**$ 139.62**	**$ 142.39**	**$ 145.22**	**$ 148.11**	**$ 151.05**	**$ 154.05**	**$ 157.11**	**$ 160.24**	**$ 163.42**	**$ 166.67**	**$ 169.98**	**$ 133.01**	**$ 92.47**	**$ 46.38**	**$1,430.29**	

At Midpoint

	CY 2025	CY 2026	CY 2027	CY 2028
Targets (MW)	336	351	380	395

Benefits - Midpoint	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	NPV
Estimated Capacity Interconnected																													
MW Installed - 2025	336																												
Estimated Capacity Interconnected																													
MW Installed - 2026		351	351	351	351	351	351	351	351	351	351	351	351	351	351	351	351	351	351	351	351	351	351	351	351	351			
Estimated Capacity Interconnected																													
MW Installed - 2027			380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380		
Estimated Capacity Interconnected																													
MW Installed - 2028				357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	357	
Total Estimated Capacity Interconnected	**336**	**687**	**1,067**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,424**	**1,088**	**737**	**357**	
Total MW Installed																													
Assume 0.5% Degradation Annually	100%	100%	99%	99%	98%	98%	97%	97%	96%	96%	95%	95%	94%	94%	93%	93%	92%	92%	91%	91%	90%	90%	90%	89%	89%	88%	88%	87%	
Solar Panel Degradation Rate (y0, y1, y2, etc)																													
MWh × Degradation =	325,463	323,836	322,217	320,605	319,002	317,407	315,820	314,241	312,670	311,107	309,551	308,003	306,463	304,931	303,406	301,889	300,380	298,878	297,384	295,897	294,417	292,945	291,480	290,023	288,573				
Avoided MWh -- 2025 Installs																													
MW Installed × Solar Coincidence × Deeradation =	121	120	120	119	119	118	117	117	116	116	115	114	114	113	113	112	112	111	111	110	109	109	108	108	107				
Avoided MW -- 2025 Installs																													
MWh × Degradation =		339,613	337,915	336,225	334,544	332,872	331,207	329,551	327,903	326,264	324,633	323,009	321,394	319,787	318,188	316,597	315,014	313,439	311,872	310,313	308,761	307,217	305,681	304,153	302,632	301,119			
Avoided MWh -- 2026 Installs																													

64	*MW Installed × Solar Coincidence × Degradation =*	Avoided MW -- 2026 Installs		126	125	124	124	123	123	122	121	121	120	120	119	118	118	117	117	116	115	115	114	114	113	113	112	111			
65	*MWh × Degradation =*	Avoided MWh -- 2027 Installs			367,914	366,074	364,244	362,423	360,611	358,808	357,014	355,229	353,452	351,685	349,927	348,177	346,436	344,704	342,981	341,266	339,559	337,861	336,172	334,491	332,819	331,155	329,499	327,851	326,212		
66	*MW Installed × Solar Coincidence × Degradation =*	Avoided MW -- 2027 Installs			135	135	134	133	133	132	131	131	130	129	129	128	128	127	126	126	125	124	124	123	123	122	121	121	120		
67	*MWh × Degradation =*	Avoided MWh -- 2028 Installs				382,064	380,154	378,253	376,362	374,480	372,607	370,744	368,891	367,046	365,211	363,385	361,568	359,760	357,961	356,172	354,391	352,619	350,856	349,101	347,356	345,619	343,891	342,172	340,461	338,758	
68	*MW Installed × Solar Coincidence × Degradation =*	Avoided MW -- 2028 Installs				127	126	125	125	124	123	123	122	122	121	120	120	119	119	118	117	117	116	116	115	115	114	113	113	112	
69	*Per NY BCA Handbook*	Avoided Generation Capacity Costs ($/MW)	$ 26.42	$ 23.93	$ 23.36	$ 23.97	$ 25.88	$ 28.78	$ 31.92	$ 38.55	$ 46.35	$ 52.43	$ 58.85	$ 65.51	$ 71.66	$ 78.14	$ 80.10	$ 82.10	$ 84.15	$ 86.25	$ 88.41	$ 90.62	$ 92.89	$ 95.21	$ 97.59	$ 100.03	$ 102.53	$ 105.09	$ 107.72	$ 110.41	
70	*Per NY BCA Handbook*	Avoided Locational-Based Marginal Price ($/MWh)	$ 41.00	$ 41.54	$ 45.54	$ 46.52	$ 48.05	$ 49.51	$ 50.89	$ 51.75	$ 52.57	$ 54.43	$ 55.41	$ 58.21	$ 59.67	$ 61.16	$ 62.69	$ 64.26	$ 65.86	$ 67.51	$ 69.20	$ 70.93	$ 72.70	$ 74.52	$ 76.38	$ 78.29	$ 80.25	$ 82.25	$ 84.31		
71	*Per NY BCA Handbook*	Net Marginal Damage Cost of CO2 ($/MWh)	$ 31.03	$ 31.81	$ 32.60	$ 33.42	$ 34.25	$ 35.11	$ 35.99	$ 36.88	$ 37.81	$ 38.75	$ 39.72	$ 40.71	$ 41.73	$ 42.78	$ 43.84	$ 44.94	$ 46.06	$ 47.22	$ 48.40	$ 49.61	$ 50.85	$ 52.12	$ 53.42	$ 54.76	$ 56.12	$ 57.53	$ 58.97	$ -	
72	*Avoided MW × AGCC $/MW =*	Avoided MW Savings ($M) -- 2025 Installs	$ 3.20	$ 2.88	$ 2.80	$ 2.86	$ 3.07	$ 3.40	$ 3.75	$ 4.50	$ 5.39	$ 6.06	$ 6.77	$ 7.50	$ 8.16	$ 8.86	$ 9.03	$ 9.21	$ 9.39	$ 9.58	$ 9.77	$ 9.97	$ 10.16	$ 10.37	$ 10.57	$ 10.78	$ 11.00	$ -	$ -	$ -	$75.48
73	*Avoided MWh × LBMP $/MWh =*	Avoided Energy Savings ($M) -- 2025 Installs	$ 13.34	$ 13.45	$ 14.68	$ 14.91	$ 15.33	$ 15.71	$ 16.07	$ 16.26	$ 16.44	$ 16.93	$ 17.15	$ 17.93	$ 18.29	$ 18.65	$ 19.02	$ 19.40	$ 19.78	$ 20.18	$ 20.58	$ 20.99	$ 21.40	$ 21.83	$ 22.26	$ 22.71	$ 23.16	$ -	$ -	$ -	$216.76
74	*Avoided MW × Cost of CO2 $/MW =*	Avoided CO2 Savings ($M) -- 2025 Installs	$ 10.10	$ 10.30	$ 10.50	$ 10.71	$ 10.93	$ 11.14	$ 11.36	$ 11.59	$ 11.82	$ 12.06	$ 12.30	$ 12.54	$ 12.79	$ 13.04	$ 13.30	$ 13.57	$ 13.84	$ 14.11	$ 14.39	$ 14.68	$ 14.97	$ 15.27	$ 15.57	$ 15.88	$ 16.20	$ -	$ -	$ -	$154.49
75	*Avoided MW Savings + Avoided Energy Savings + Avoided CO2 Savings =*	**Total Benefits ($M) -- 2025 Installs**	**$ 26.64**	**$ 26.63**	**$ 27.98**	**$ 28.48**	**$ 29.32**	**$ 30.25**	**$ 31.19**	**$ 32.36**	**$ 33.64**	**$ 35.05**	**$ 36.22**	**$ 37.97**	**$ 39.24**	**$ 40.55**	**$ 41.35**	**$ 42.18**	**$ 43.01**	**$ 43.87**	**$ 44.74**	**$ 45.63**	**$ 46.54**	**$ 47.46**	**$ 48.41**	**$ 49.37**	**$ 50.35**	**$ -**	**$ -**	**$ -**	**$446.73**
76	*Avoided MW × AGCC $/MW =*	Avoided MW Savings ($M) -- 2026 Installs	$ -	$ 3.01	$ 2.92	$ 2.98	$ 3.21	$ 3.55	$ 3.91	$ 4.70	$ 5.63	$ 6.33	$ 7.07	$ 7.83	$ 8.53	$ 9.25	$ 9.43	$ 9.62	$ 9.81	$ 10.01	$ 10.21	$ 10.41	$ 10.62	$ 10.83	$ 11.04	$ 11.26	$ 11.49	$ 11.72	$ -	$ -	$78.22
77	*Avoided MWh × LBMP $/MWh =*	Avoided Energy Savings ($M) -- 2026 Installs	$ -	$ 14.11	$ 15.39	$ 15.64	$ 16.08	$ 16.48	$ 16.86	$ 17.06	$ 17.24	$ 17.76	$ 17.99	$ 18.80	$ 19.18	$ 19.56	$ 19.95	$ 20.34	$ 20.75	$ 21.16	$ 21.58	$ 22.01	$ 22.45	$ 22.89	$ 23.35	$ 23.81	$ 24.29	$ 24.77	$ -	$ -	$219.47
78	*Avoided MW × Cost of CO2 $/MW =*	Avoided CO2 Savings ($M) -- 2026 Installs	$ -	$ 10.80	$ 11.02	$ 11.24	$ 11.46	$ 11.69	$ 11.92	$ 12.16	$ 12.40	$ 12.64	$ 12.89	$ 13.15	$ 13.41	$ 13.68	$ 13.95	$ 14.23	$ 14.51	$ 14.80	$ 15.09	$ 15.39	$ 15.70	$ 16.01	$ 16.33	$ 16.65	$ 16.99	$ 17.32	$ -	$ -	$155.76
79	*Avoided MW Savings + Avoided Energy Savings + Avoided CO2 Savings =*	**Total Benefits ($M) -- 2026 Installs**	**$ -**	**$ 27.92**	**$ 29.33**	**$ 29.86**	**$ 30.74**	**$ 31.71**	**$ 32.69**	**$ 33.91**	**$ 35.26**	**$ 36.73**	**$ 37.96**	**$ 39.79**	**$ 41.12**	**$ 42.49**	**$ 43.33**	**$ 44.19**	**$ 45.07**	**$ 45.97**	**$ 46.88**	**$ 47.81**	**$ 48.76**	**$ 49.73**	**$ 50.72**	**$ 51.73**	**$ 52.76**	**$ 53.81**	**$ -**	**$ -**	**$453.46**
80	*Avoided MW × AGCC $/MW =*	Avoided MW Savings ($M) -- 2027 Installs	$ -	$ -	$ 3.16	$ 3.23	$ 3.47	$ 3.84	$ 4.24	$ 5.09	$ 6.09	$ 6.86	$ 7.66	$ 8.48	$ 9.23	$ 10.02	$ 10.21	$ 10.42	$ 10.62	$ 10.84	$ 11.05	$ 11.27	$ 11.49	$ 11.72	$ 11.96	$ 12.19	$ 12.44	$ 12.68	$ 12.94	$ -	$84.42
81	*Avoided MWh × LBMP $/MWh =*	Avoided Energy Savings ($M) -- 2027 Installs	$ -	$ -	$ 16.76	$ 17.03	$ 17.50	$ 17.94	$ 18.35	$ 18.57	$ 18.77	$ 19.33	$ 19.59	$ 20.47	$ 20.88	$ 21.29	$ 21.72	$ 22.15	$ 22.59	$ 23.04	$ 23.50	$ 23.96	$ 24.44	$ 24.93	$ 25.42	$ 25.93	$ 26.44	$ 26.97	$ 27.50	$ -	$230.89
82	*Avoided MW × Cost of CO2 $/MW =*	Avoided CO2 Savings ($M) -- 2027 Installs	$ -	$ -	$ 11.99	$ 12.23	$ 12.48	$ 12.72	$ 12.98	$ 13.23	$ 13.50	$ 13.77	$ 14.04	$ 14.32	$ 14.60	$ 14.89	$ 15.19	$ 15.49	$ 15.80	$ 16.11	$ 16.43	$ 16.76	$ 17.09	$ 17.43	$ 17.78	$ 18.13	$ 18.49	$ 18.86	$ 19.24	$ -	$163.05
83	*Avoided MW Savings + Avoided Energy Savings + Avoided CO2 Savings =*	**Total Benefits ($M) -- 2027 Installs**	**$ -**	**$ -**	**$ 31.91**	**$ 32.49**	**$ 33.45**	**$ 34.51**	**$ 35.57**	**$ 36.90**	**$ 38.36**	**$ 39.96**	**$ 41.28**	**$ 43.27**	**$ 44.71**	**$ 46.20**	**$ 47.12**	**$ 48.06**	**$ 49.01**	**$ 49.99**	**$ 50.98**	**$ 51.99**	**$ 53.03**	**$ 54.08**	**$ 55.16**	**$ 56.25**	**$ 57.37**	**$ 58.51**	**$ 59.67**	**$ -**	**$478.36**
84	*Avoided MW × AGCC $/MW =*	Avoided MW Savings ($M) -- 2028 Installs	$ -	$ -	$ -	$ 3.03	$ 3.26	$ 3.61	$ 3.98	$ 4.78	$ 5.72	$ 6.44	$ 7.19	$ 7.97	$ 8.67	$ 9.41	$ 9.60	$ 9.79	$ 9.98	$ 10.18	$ 10.38	$ 10.59	$ 10.80	$ 11.01	$ 11.23	$ 11.46	$ 11.68	$ 11.92	$ 12.15	$ 12.39	$79.19
85	*Avoided MWh × LBMP $/MWh =*	Avoided Energy Savings ($M) -- 2028 Installs	$ -	$ -	$ -	$ 17.77	$ 18.27	$ 18.73	$ 19.15	$ 19.38	$ 19.59	$ 20.18	$ 20.44	$ 21.37	$ 21.79	$ 22.22	$ 22.67	$ 23.12	$ 23.58	$ 24.04	$ 24.52	$ 25.01	$ 25.51	$ 26.01	$ 26.53	$ 27.06	$ 27.60	$ 28.14	$ 28.70	$ 29.27	$231.93
86	*Avoided MW × Cost of CO2 $/MW =*	Avoided CO2 Savings ($M) -- 2028 Installs	$ -	$ -	$ -	$ 12.77	$ 13.02	$ 13.28	$ 13.54	$ 13.81	$ 14.09	$ 14.37	$ 14.65	$ 14.94	$ 15.24	$ 15.54	$ 15.85	$ 16.17	$ 16.49	$ 16.82	$ 17.15	$ 17.49	$ 17.84	$ 18.19	$ 18.56	$ 18.92	$ 19.30	$ 19.68	$ 20.08	$ 20.47	$163.60
87	*Avoided MW Savings + Avoided Energy Savings + Avoided CO2 Savings =*	**Total Benefits ($M) -- 2028 Installs**	**$ -**	**$ -**	**$ -**	**$ 33.57**	**$ 34.55**	**$ 35.61**	**$ 36.68**	**$ 37.98**	**$ 39.40**	**$ 40.99**	**$ 42.29**	**$ 44.28**	**$ 45.70**	**$ 47.18**	**$ 48.12**	**$ 49.07**	**$ 50.05**	**$ 51.04**	**$ 52.06**	**$ 53.09**	**$ 54.15**	**$ 55.22**	**$ 56.32**	**$ 57.44**	**$ 58.58**	**$ 59.74**	**$ 60.93**	**$ 62.14**	**$ 474.73**
88	*Avoided MW × AGCC $/MW =*	Avoided MW Savings ($M) -- All Years	$ 3.20	$ 5.89	$ 8.88	$ 12.10	$ 13.01	$ 14.39	$ 15.88	$ 19.08	$ 22.82	$ 25.69	$ 28.69	$ 31.78	$ 34.59	$ 37.53	$ 38.28	$ 39.04	$ 39.81	$ 40.61	$ 41.41	$ 42.24	$ 43.07	$ 43.93	$ 44.80	$ 45.69	$ 46.60	$ 36.31	$ 25.09	$ 12.39	$317.31
89	*Avoided MWh × LBMP $/MWh =*	Avoided Energy Savings ($M) -- All Years	$ 13.34	$ 27.56	$ 46.82	$ 65.36	$ 67.17	$ 68.86	$ 70.44	$ 71.27	$ 72.03	$ 74.20	$ 75.17	$ 78.57	$ 80.13	$ 81.73	$ 83.35	$ 85.01	$ 86.70	$ 88.42	$ 90.18	$ 91.97	$ 93.80	$ 95.66	$ 97.56	$ 99.50	$ 101.48	$ 79.88	$ 56.21	$ 29.27	$899.06
90	*Avoided MW × Cost of CO2 $/MW =*	Avoided CO2 Savings ($M) -- All Years	$ 10.10	$ 21.10	$ 33.52	$ 46.95	$ 47.88	$ 48.83	$ 49.80	$ 50.79	$ 51.80	$ 52.83	$ 53.88	$ 54.95	$ 56.05	$ 57.16	$ 58.30	$ 59.45	$ 60.64	$ 61.84	$ 63.07	$ 64.32	$ 65.60	$ 66.91	$ 68.24	$ 69.59	$ 70.98	$ 55.87	$ 39.31	$ 20.47	$636.90
91	*Avoided MW Savings + Avoided Energy Savings + Avoided CO2 Savings =*	**Total Benefits ($M) -- All Years**	**$ 26.64**	**$ 54.55**	**$ 89.22**	**$ 124.41**	**$ 128.06**	**$ 132.09**	**$ 136.12**	**$ 141.15**	**$ 146.66**	**$ 152.73**	**$ 157.74**	**$ 165.31**	**$ 170.77**	**$ 176.42**	**$ 179.92**	**$ 183.50**	**$ 187.15**	**$ 190.87**	**$ 194.66**	**$ 198.53**	**$ 202.47**	**$ 206.50**	**$ 210.60**	**$ 214.79**	**$ 219.06**	**$ 172.06**	**$ 120.61**	**$ 62.14**	**$1,853.28**

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94	**At Maximum**	**CY 2025**	**CY 2026**	**CY 2027**	**CY 2028**
95	Targets (MW)	388	405	438	455

96

97		**Benefits - Maximum**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**NPV**
98	*Estimated Capacity Interconnected*	MW Installed - 2025	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388				
99	*Estimated Capacity Interconnected*	MW Installed - 2026		405	405	405	405	405	405	405	405	405	405	405	405	405	405	405	405	405	405	405	405	405	405	405	405	405			
100	*Estimated Capacity Interconnected*	MW Installed - 2027			438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438	438		
101	*Estimated Capacity Interconnected*	MW Installed - 2028				412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	
102	*Total Estimated Capacity Interconnected*	Total MW Installed	**388**	**793**	**1,231**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,643**	**1,255**	**850**	**412**	
103	*Assume 0.5% Degradation Annually*	Solar Panel Degradation Rate (y0, y1, y2, etc)	100%	100%	99%	99%	98%	98%	97%	97%	96%	96%	95%	95%	94%	94%	93%	93%	92%	92%	91%	91%	90%	90%	90%	89%	89%	88%	88%	87%	
104	*MWh × Degradation =*	Avoided MWh -- 2025 Installs	488,193	485,752	483,323	480,907	478,502	476,110	473,729	471,360	469,004	466,659	464,325	462,004	459,694	457,395	455,108	452,833	450,569	448,316	446,074	443,844	441,625	439,416	437,219	435,033	432,858				
105	*MW Installed × Solar Coincidence × Degradation =*	Avoided MW -- 2025 Installs	140	139	138	138	137	136	136	135	134	134	133	132	132	131	130	130	129	128	128	127	126	126	125	124	124				
106	*MWh × Degradation =*	Avoided MWh -- 2026 Installs		509,419	506,872	504,338	501,816	499,307	496,810	494,326	491,855	489,395	486,948	484,514	482,091	479,681	477,282	474,896	472,521	470,159	467,808	465,469	463,141	460,826	458,522	456,229	453,948	451,678			
107	*MW Installed × Solar Coincidence × Degradation =*	Avoided MW -- 2026 Installs		145	144	144	143	142	141	141	140	139	139	138	137	137	136	135	135	134	133	133	132	131	131	130	129	129			
108	*MWh × Degradation =*	Avoided MWh -- 2027 Installs			551,870	549,111	546,365	543,633	540,915	538,211	535,519	532,842	530,178	527,527	524,889	522,265	519,653	517,055	514,470	511,897	509,338	506,791	504,257	501,736	499,227	496,731	494,248	491,776	489,317		
109	*MW Installed × Solar Coincidence × Degradation =*	Avoided MW -- 2027 Installs			156	155	155	154	153	152	151	151	150	149	148	148	147	146	146	145	144	143	143	142	141	141	140	139	138		
110	*MWh × Degradation =*	Avoided MWh -- 2028 Installs	-	-	-	573,096	570,231	567,379	564,542	561,720	558,911	556,117	553,336	550,569	547,816	545,077	542,352	539,640	536,942	534,257	531,586	528,928	526,283	523,652	521,034	518,429	515,837	513,257	510,691	508,138	
111	*MW Installed × Solar Coincidence × Degradation =*	Avoided MW -- 2028 Installs	-	-	-	146	145	145	144	143	142	142	141	140	140	139	138	138	137	136	136	135	134	134	133	132	132	131	130	130	
112	*Per NY BCA Handbook*	Avoided Generation Capacity Costs ($/MW)	$ 26.42	$ 23.93	$ 23.36	$ 23.97	$ 25.88	$ 28.78	$ 31.92	$ 38.55	$ 46.35	$ 52.43	$ 58.85	$ 65.51	$ 71.66	$ 78.14	$ 80.10	$ 82.10	$ 84.15	$ 86.25	$ 88.41	$ 90.62	$ 92.89	$ 95.21	$ 97.59	$ 100.03	$ 102.53	$ 105.09	$ 107.72	$ 110.41	
113	*Per NY BCA Handbook*	Avoided Locational-Based Marginal Price ($/MWh)	$ 41.00	$ 41.54	$ 45.54	$ 46.52	$ 48.05	$ 49.51	$ 50.89	$ 51.75	$ 52.57	$ 54.43	$ 55.41	$ 58.21	$ 59.67	$ 61.16	$ 62.69	$ 64.26	$ 65.86	$ 67.51	$ 69.20	$ 70.93	$ 72.70	$ 74.52	$ 76.38	$ 78.29	$ 80.25	$ 82.25	$ 84.31	$ 95.52	
114	*Per NY BCA Handbook*	Net Marginal Damage Cost of CO2 ($/MWh)	$ 31.03	$ 31.81	$ 32.60	$ 33.42	$ 34.25	$ 35.11	$ 35.99	$ 36.88	$ 37.81	$ 38.75	$ 39.72	$ 40.71	$ 41.73	$ 42.78	$ 43.84	$ 44.94	$ 46.06	$ 47.22	$ 48.40	$ 49.61	$ 50.85	$ 52.12	$ 53.42	$ 54.76	$ 56.12	$ 57.53	$ 58.97	$ 60.44	
115	*Avoided MW × AGCC $/MW =*	Avoided MW Savings ($M) -- 2025 Installs	$ 3.69	$ 3.33	$ 3.23	$ 3.30	$ 3.54	$ 3.92	$ 4.33	$ 5.20	$ 6.22	$ 7.00	$ 7.82	$ 8.66	$ 9.43	$ 10.23	$ 10.43	$ 10.64	$ 10.85	$ 11.06	$ 11.28	$ 11.51	$ 11.74	$ 11.97	$ 12.21	$ 12.45	$ 12.70	$ -	$ -	$ -	$87.16
116	*Avoided MWh × LBMP $/MWh =*	Avoided Energy Savings ($M) -- 2025 Installs	$ 20.02	$ 20.18	$ 22.01	$ 22.37	$ 22.99	$ 23.57	$ 24.11	$ 24.39	$ 24.66	$ 25.40	$ 25.73	$ 26.89	$ 27.43	$ 27.97	$ 28.53	$ 29.10	$ 29.68	$ 30.26	$ 30.87	$ 31.48	$ 32.11	$ 32.74	$ 33.39	$ 34.06	$ 34.74	$ -	$ -	$ -	$325.14
117	*Avoided MW × Cost of CO2 $/MW =*	Avoided CO2 Savings ($M) -- 2025 Installs	$ 15.15	$ 15.45	$ 15.76	$ 16.07	$ 16.39	$ 16.72	$ 17.05	$ 17.39	$ 17.73	$ 18.08	$ 18.44	$ 18.81	$ 19.18	$ 19.57	$ 19.95	$ 20.35	$ 20.76	$ 21.17	$ 21.59	$ 22.02	$ 22.45	$ 22.90	$ 23.36	$ 23.82	$ 24.29	$ -	$ -	$ -	$231.73
118	*Avoided MW Savings + Avoided Energy Savings + Avoided CO2 Savings =*	**Total Benefits ($M) -- 2025 Installs**	**$ 38.86**	**$ 38.95**	**$ 41.00**	**$ 41.74**	**$ 42.93**	**$ 44.21**	**$ 45.48**	**$ 46.98**	**$ 48.61**	**$ 50.48**	**$ 51.99**	**$ 54.36**	**$ 56.04**	**$ 57.77**	**$ 58.91**	**$ 60.08**	**$ 61.28**	**$ 62.50**	**$ 63.74**	**$ 65.01**	**$ 66.30**	**$ 67.61**	**$ 68.96**	**$ 70.33**	**$ 71.73**	**$ -**	**$ -**	**$ -**	**$644.03**
119	*Avoided MW × AGCC $/MW =*	Avoided MW Savings ($M) -- 2026 Installs	$ -	$ 3.47	$ 3.37	$ 3.44	$ 3.70	$ 4.09	$ 4.52	$ 5.43	$ 6.49	$ 7.31	$ 8.16	$ 9.04	$ 9.84	$ 10.67	$ 10.89	$ 11.10	$ 11.32	$ 11.55	$ 11.78	$ 12.01	$ 12.25	$ 12.49	$ 12.74	$ 13.00	$ 13.25	$ 13.52	$ -	$ -	$90.26
120	*Avoided MWh × LBMP $/MWh =*	Avoided Energy Savings ($M) -- 2026 Installs	$ -	$ 21.16	$ 23.09	$ 23.46	$ 24.11	$ 24.72	$ 25.29	$ 25.58	$ 25.86	$ 26.64	$ 26.98	$ 28.20	$ 28.77	$ 29.34	$ 29.92	$ 30.51	$ 31.12	$ 31.74	$ 32.37	$ 33.01	$ 33.67	$ 34.34	$ 35.02	$ 35.72	$ 36.43	$ 37.15	$ -	$ -	$329.20
121	*Avoided MW × Cost of CO2 $/MW =*	Avoided CO2 Savings ($M) -- 2026 Installs	$ -	$ 16.20	$ 16.52	$ 16.85	$ 17.19	$ 17.53	$ 17.88	$ 18.23	$ 18.60	$ 18.97	$ 19.34	$ 19.73	$ 20.12	$ 20.52	$ 20.93	$ 21.34	$ 21.77	$ 22.20	$ 22.64	$ 23.09	$ 23.55	$ 24.02	$ 24.49	$ 24.98	$ 25.48	$ 25.98	$ -	$ -	$233.64
122	*Avoided MW Savings + Avoided Energy Savings + Avoided CO2 Savings =*	**Total Benefits ($M) -- 2026 Installs**	**$ -**	**$ 40.83**	**$ 42.98**	**$ 43.76**	**$ 45.00**	**$ 46.34**	**$ 47.68**	**$ 49.24**	**$ 50.94**	**$ 52.91**	**$ 54.49**	**$ 56.97**	**$ 58.72**	**$ 60.53**	**$ 61.73**	**$ 62.96**	**$ 64.21**	**$ 65.49**	**$ 66.79**	**$ 68.12**	**$ 69.47**	**$ 70.85**	**$ 72.26**	**$ 73.69**	**$ 75.16**	**$ 76.65**	**$ -**	**$ -**	**$653.11**
123	*Avoided MW × AGCC $/MW =*	Avoided MW Savings ($M) -- 2027 Installs	$ -	$ -	$ 3.65	$ 3.72	$ 4.00	$ 4.43	$ 4.88	$ 5.87	$ 7.02	$ 7.90	$ 8.83	$ 9.78	$ 10.64	$ 11.54	$ 11.77	$ 12.01	$ 12.25	$ 12.49	$ 12.74	$ 12.99	$ 13.25	$ 13.51	$ 13.78	$ 14.05	$ 14.33	$ 14.62	$ 14.91	$ -	$97.31
124	*Avoided MWh × LBMP $/MWh =*	Avoided Energy Savings ($M) -- 2027 Installs	$ -	$ -	$ 25.13	$ 25.54	$ 26.25	$ 26.91	$ 27.53	$ 27.85	$ 28.15	$ 29.00	$ 29.38	$ 30.71	$ 31.32	$ 31.94	$ 32.58	$ 33.22	$ 33.88	$ 34.56	$ 35.24	$ 35.94	$ 36.66	$ 37.39	$ 38.13	$ 38.89	$ 39.66	$ 40.45	$ 41.25	$ -	$346.34
125	*Avoided MW × Cost of CO2 $/MW =*	Avoided CO2 Savings ($M) -- 2027 Installs	$ -	$ -	$ 17.99	$ 18.35	$ 18.71	$ 19.09	$ 19.46	$ 19.85	$ 20.25	$ 20.65	$ 21.06	$ 21.48	$ 21.90	$ 22.34	$ 22.78	$ 23.24	$ 23.70	$ 24.17	$ 24.65	$ 25.14	$ 25.64	$ 26.15	$ 26.67	$ 27.20	$ 27.74	$ 28.29	$ 28.85	$ -	$244.57
126	*Avoided MW Savings + Avoided Energy Savings + Avoided CO2 Savings =*	**Total Benefits ($M) -- 2027 Installs**	**$ -**	**$ -**	**$ 46.77**	**$ 47.62**	**$ 48.97**	**$ 50.43**	**$ 51.88**	**$ 53.58**	**$ 55.42**	**$ 57.55**	**$ 59.26**	**$ 61.96**	**$ 63.86**	**$ 65.83**	**$ 67.13**	**$ 68.47**	**$ 69.83**	**$ 71.22**	**$ 72.63**	**$ 74.08**	**$ 75.55**	**$ 77.05**	**$ 78.58**	**$ 80.14**	**$ 81.74**	**$ 83.36**	**$ 85.02**	**$ -**	**$688.22**
127	*Avoided MW × AGCC $/MW =*	Avoided MW Savings ($M) -- 2028 Installs				$ 3.50	$ 3.76	$ 4.16	$ 4.59	$ 5.52	$ 6.60	$ 7.43	$ 8.30	$ 9.20	$ 10.01	$ 10.86	$ 11.07	$ 11.29	$ 11.52	$ 11.75	$ 11.98	$ 12.22	$ 12.46	$ 12.71	$ 12.96	$ 13.22	$ 13.48	$ 13.75	$ 14.02	$ 14.30	$109.10
128	*Avoided MWh × LBMP $/MWh =*	Avoided Energy Savings ($M) -- 2028 Installs				$ 26.66	$ 27.40	$ 28.09	$ 28.73	$ 29.07	$ 29.38	$ 30.27	$ 30.66	$ 32.05	$ 32.69	$ 33.34	$ 34.00	$ 34.67	$ 35.36	$ 36.07	$ 36.78	$ 37.51	$ 38.26	$ 39.02	$ 39.80	$ 40.59	$ 41.39	$ 42.22	$ 43.06	$ 43.91	$415.30
129	*Avoided MW × Cost of CO2 $/MW =*	Avoided CO2 Savings ($M) -- 2028 Installs				$ 19.15	$ 19.53	$ 19.92	$ 20.32	$ 20.72	$ 21.13	$ 21.55	$ 21.98	$ 22.42	$ 22.86	$ 23.32	$ 23.78	$ 24.25	$ 24.73	$ 25.23	$ 25.73	$ 26.24	$ 26.76	$ 27.29	$ 27.83	$ 28.39	$ 28.95	$ 29.53	$ 30.11	$ 30.71	$292.95
130	*Avoided MW Savings + Avoided Energy Savings + Avoided CO2 Savings =*	**Total Benefits ($M) -- 2028 Installs**	**$ -**	**$ -**	**$ -**	**$ 49.31**	**$ 50.69**	**$ 52.17**	**$ 53.64**	**$ 55.31**	**$ 57.12**	**$ 59.25**	**$ 60.94**	**$ 63.66**	**$ 65.56**	**$ 67.51**	**$ 68.85**	**$ 70.22**	**$ 71.62**	**$ 73.04**	**$ 74.49**	**$ 75.97**	**$ 77.48**	**$ 79.02**	**$ 80.59**	**$ 82.19**	**$ 83.83**	**$ 85.49**	**$ 87.19**	**$ 88.93**	**$684.70**
131	*Avoided MW × AGCC $/MW =*	Avoided MW Savings ($M) -- All Years	$ 3.69	$ 6.80	$ 10.25	$ 13.97	$ 15.01	$ 16.60	$ 18.32	$ 22.02	$ 26.34	$ 29.64	$ 33.11	$ 36.67	$ 39.91	$ 43.30	$ 44.16	$ 45.04	$ 45.94	$ 46.85	$ 47.78	$ 48.73	$ 49.70	$ 50.69	$ 51.69	$ 52.72	$ 53.77	$ 41.89	$ 28.93	$ 14.30	$366.12
132	*Avoided MWh × LBMP $/MWh =*	Avoided Energy Savings ($M) -- All Years	$ 20.02	$ 41.33	$ 70.23	$ 98.03	$ 100.76	$ 103.29	$ 105.66	$ 106.90	$ 108.05	$ 111.30	$ 112.75	$ 117.86	$ 120.20	$ 122.59	$ 125.02	$ 127.51	$ 130.04	$ 132.63	$ 135.26	$ 137.95	$ 140.69	$ 143.49	$ 146.34	$ 149.25	$ 152.22	$ 119.82	$ 84.31	$ 43.91	$1.348.59
133	*Avoided MW × Cost of CO2 $/MW =*	Avoided CO2 Savings ($M) -- All Years	$ 15.15	$ 31.65	$ 50.27	$ 70.42	$ 71.82	$ 73.25	$ 74.71	$ 76.19	$ 77.70	$ 79.25	$ 80.82	$ 82.43	$ 84.07	$ 85.74	$ 87.44	$ 89.18	$ 90.95	$ 92.76	$ 94.61	$ 96.49	$ 98.40	$ 100.36	$ 102.35	$ 104.39	$ 106.46	$ 83.80	$ 58.97	$ 30.71	$955.35
134	*Avoided MW Savings + Avoided Energy Savings + Avoided CO2 Savings =*	**Total Benefits ($M) -- All Years**	**$ 38.86**	**$ 79.78**	**$ 130.75**	**$ 182.42**	**$ 187.59**	**$ 193.15**	**$ 198.68**	**$ 205.11**	**$ 212.09**	**$ 220.19**	**$ 226.68**	**$ 236.96**	**$ 244.18**	**$ 251.63**	**$ 256.63**	**$ 261.73**	**$ 266.93**	**$ 272.24**	**$ 277.65**	**$ 283.17**	**$ 288.80**	**$ 294.54**	**$ 300.39**	**$ 306.36**	**$ 312.45**	**$ 245.51**	**$ 172.21**	**$ 88.93**	**$2,670.06**

Testimony of Climate Leadership and Community Protection Act Panel

Exhibit___(CLCPA-11)

EV Managed Charging EAM Net Benefits

EV Managed Charging Net Benefits Summary

	a	b	c	d
1		Min	Mid	Max
2	Benefit	$ 16.5	$ 20.3	$ 26.7
3	Cost	$ 6.2	$ 7.9	$ 10.2
4	Societal Cost Test	$ 2.7	$ 2.6	$ 2.6
5				
6	Benefits ($MM)	Min	Mid	Max
7	Distribution Peak Avoidance	$ 12.4	$ 15.3	$ 20.1
8	Transmission Peak Avoidance	$ 2.2	$ 2.7	$ 3.6
9	Avoided Gen Capacity Cost	$ 1.9	$ 2.3	$ 3.0
10	Total Benefits (NPV)	$ 16.5	$ 20.3	$ 26.7
11				
12	Costs ($MM)	Min	Mid	Max
13	Total Costs (NPV)	$ 6.2	$ 7.9	$ 10.2

Testimony of Climate Leadership and Community Protection Act Panel

Exhibit___(CLCPA-12)

Medium and Heavy Duty Transportation Electrification EAM Net Benefits

Medium Heavy Duty Transportation Electrification EAM Net Benefits Summary

	a	b	c	d
		Min	Mid	Max
1	Benefit ($MM)	$ 138.8	$ 208.1	$ 277.5
2	Cost ($MM)	$ 56.0	$ 84.0	$ 112.0
3	Societal Cost Test	2.48	2.48	2.48
4				
5	Benefits ($MM)	Min	Mid	Max
6	Net Avoided CO2	$ 18.2	$ 27.3	$ 36.5
7	Net Avoided PM2.5	$ 2.1	$ 3.1	$ 4.1
8	Avoided Non-Electric Fuel Cost	$ 118.5	$ 177.7	$ 237.0
9	Total Benefits (NPV)	$ 138.8	$ 208.1	$ 277.5
10				
11	Costs ($MM)	Min	Mid	Max
12	Charging Infrastructure Costs	$ 56.0	$ 84.0	$ 112.0
13	Increased Generation Capacity Costs	$ 25.3	$ 38.0	$ 50.7
14	Increased LBMP	$ 13.0	$ 19.5	$ 26.0
15	Total Costs (NPV)	$ 94.3	$ 141.5	$ 188.7