A Framework for Gas Company Climate Planning in New York

MJB & A
an ERM Group company

May 2021

MJB & A
an ERM Group Company

Table of Contents

Executive Summary 4

Introduction 7

New York's Gas Planning Proceeding 7

Principles for a Gas Company Climate Planning Framework 12

Recommended Methodology 17

Conclusion 31

Appendix A: Gas Company Climate Planning Tool 32

Endnotes 36

Acknowledgements

The following paper was prepared by M.J. Bradley & Associates (MJB&A), an ERM Group Company, at the request of Environmental Defense Fund (EDF). The intent of the paper is to provide a recommended framework for assessing greenhouse gas (GHG) emissions to aide regulators, policymakers, natural gas utilities and stakeholders in integrating and aligning gas planning with climate change laws and policies in a consistent and transparent manner.

Brian Jones, Dana Lowell, Dave Seamonds, Luke Hellgren, Sophia Hill, and Alissa Huntington of MJB&A made important contributions to this report.

This report is available at www.mjbradley.com

About M.J. Bradley & Associates, LLC

MJB&A, an ERM Group company, provides strategic consulting services to address energy and environmental issues for the private, public, and non-profit sectors. MJB&A creates value and addresses risks with a comprehensive approach to strategy and implementation, ensuring clients have timely access to information and the tools to use it to their advantage. Our approach fuses private sector strategy with public policy in air quality, energy, climate change, environmental markets, energy efficiency, renewable energy, transportation, and advanced technologies. Our international client base includes electric and natural gas utilities, major transportation fleet operators, investors, clean technology firms, environmental groups and government agencies. Our seasoned team brings a multi-sector perspective, informed expertise, and creative solutions to each client, capitalizing on extensive experience in energy markets, environmental policy, law, engineering, economics and business. For more information we encourage you to visit our website, www.mjbradley.com.

For questions or comments, please contact:

Brian Jones
Senior Vice President
M.J. Bradley & Associates
+1 978 369 5533
bjones@mjbradley.com

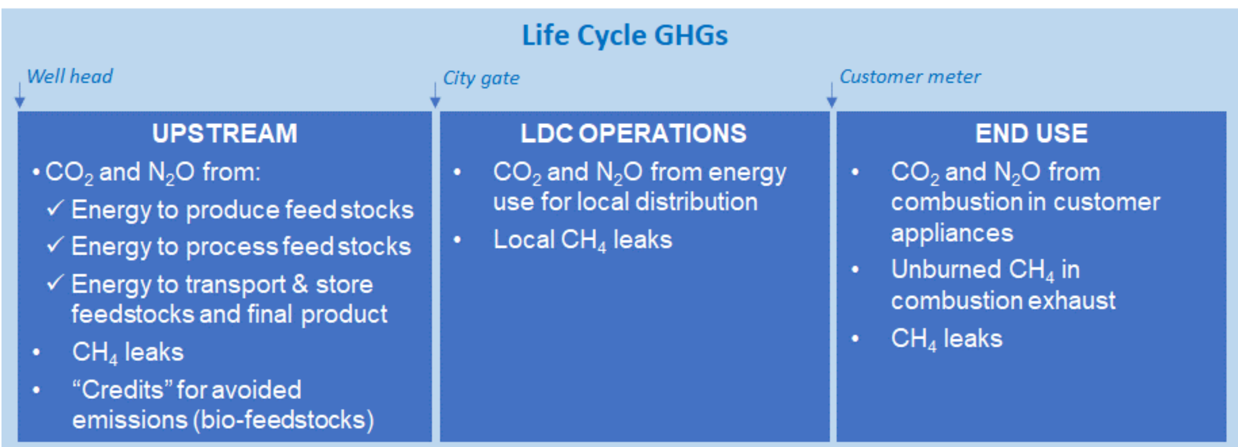
Executive Summary

This report presents a methodology to evaluate the life cycle greenhouse gas (GHG) emissions of natural gas supplied to customers in New York state, to ensure that long range gas planning by the state's natural gas local distribution companies (LDCs) align with the state's *Climate Leadership and Community Protection Act* (CLCPA) and other state and local climate and clean energy goals and targets. Independent analysis has concluded that for New York to succeed in achieving the CLCPA target of an 85 percent reduction in economy-wide GHG emissions below 1990 levels by 2050, total GHG emissions from natural gas use will need to decline significantly from current levels.

The Gas Company Climate Planning Framework is comprehensive and flexible, so it can be used in several ways. It can be used to evaluate different portfolios of gas supply options against each other, to compare specific discrete options against each other, or to evaluate the effect of a proposed portfolio on state-wide GHG reduction goals. In conjunction with this report, MJB&A developed an Excel-based tool—the Gas Company Climate Planning Tool—to help LDCs and other stakeholders evaluate the impacts of alternative supply- and demand-side scenarios.[1]

The Gas Company Climate Planning Framework consists of a life cycle approach that accounts for GHGs emitted throughout the entire value chain of natural gas and other fuels, from production all the way through end use. For convenience, the framework follows the convention of dividing the fuel life cycle into three segments that are consistent with the data sources recommended for use in calculating emissions at each stage: 1) upstream, 2) LDC operations, and 3) end-use (see Figure 1).

Figure ES 1: Scope of Natural Gas Supply Life Cycle GHG Analysis



The Gas Company Climate Planning Framework is based on the following six core principles:

1. Account for all combustion-related GHG emissions and fugitive methane emissions.
2. Account for both supply- and demand-side options to manage and meet gas demand.
3. Use the most recent, publicly available data.
4. Identify and incorporate significant uncertainties.

[1] Please see Appendix A for more details on the Gas Company Climate Planning Tool. To download this tool, view its supplementary user guide, and access other MJB&A tools, please register at www.mjbradley.com/analytical-resources.

5. Align the analysis with economy-wide GHG emission reduction targets under the CLCPA.
6. Monetize life cycle GHGs using the Social Cost of Carbon Dioxide, the Social Cost of Methane, and the Social Cost of Nitrous Oxide.

Natural gas LDCs have numerous options to meet net annual total energy demand and reducing GHG emissions; these options can be broadly classified as supply-side and demand-side approaches. On the supply side, LDCs could contract for more natural gas, to be delivered through existing, upgraded, or new pipelines. LDCs could also contract for purchase of alternative, lower-carbon energy sources to be blended with natural gas—either upstream or locally—for delivery to their customers. These alternatives include biomethane produced from waste feedstocks such as landfills, wastewater treatment plants, and livestock manure.[2] Additional alternatives include hydrogen produced from different feedstocks including natural gas, biomethane, nuclear and renewable electricity.

On the demand side, LDCs could reduce total annual LDC customer demand for natural gas. Examples include efficiency programs to provide natural gas customers with incentives to install more efficient gas appliances or to improve building insulation and/or windows to reduce total heating demand. Another example would be programs to incentivize individual natural gas customers to replace existing natural gas appliances with air or ground source heat pumps that use electricity to provide space and/or water heating rather than natural gas. More ambitious fuel switching options include development of "district heating systems" that supply energy for space and water heating to multiple buildings via distribution of steam or hot water, with the steam/hot water produced by waste heat and/or shared loop geothermal systems.

The recommended methodology for calculating the life cycle GHG emissions of any gas supply option is as follow:

1. Use an activity factor and emission factors to calculate the emissions of each GHG (CO_2, CH_4, N_2O) at each stage of the life cycle.
2. Sum the emissions of each pollutant across the three life cycle stages (Upstream, LDC Operations, and End-Use).
3. Multiply total CH_4 and N_2O emissions by the appropriate GWP(s) to calculate their CO_2-equivalence (CO_2-e).
4. Sum the total CO_2, CH_4, and N_2O emissions to estimate total life cycle GHG emissions in CO_2-e (again, using the appropriate GWP(s)).
5. Use values for the Social Cost of Carbon Dioxide, Social Cost of Methane, and Social Cost of Nitrous Oxide to monetize the estimated total GHG emissions.

The Gas Company Climate Planning Framework recommends, whenever possible, the use of peer-reviewed, publicly available emission factors to estimate emissions across the fuel life cycle. Relevant, significant uncertainties associated with data and emissions factors, especially methane leakage assumptions, should be addressed by using a range estimate that incorporates best available current information.

[2] Biomethane (also known as "renewable natural gas") is produced either by "upgrading" biogas (a process that removes any CO_2 and other contaminants present in the biogas). It is indistinguishable from natural gas and so can be used without the need for any changes in transmission and distribution infrastructure or end-user equipment.

For transparency and consistency with New York State planning, the Gas Company Climate Planning Framework recommends that NY LDCs use data and information developed by state agencies including, but not limited to: long term forecasts for annual natural gas demand for electric generation and annual electric grid emissions intensity produced by the New York Independent System Operator (NYISO); New York State Energy Research and Development Authority (NYSERDA), and New York Department of Environmental Conservation (NY DEC).

Finally, to facilitate the integration of GHG goals into the more traditional economic aspects of gas planning, the Gas Company Climate Planning Framework recommends that LDCs calculate the monetized value of GHGs associated with gas supply portfolios using Value of Carbon produced by NY DEC. Integrating this framework into gas supply planning will need to balance the potentially competing goals of reducing GHG emissions while providing customers with access to reliable, safe, and affordable energy.

Introduction

The purpose of this report is to outline a methodology to quantify the life cycle GHG emissions of natural gas supplied to customers in New York State, to ensure that long-range gas planning by the state's natural gas LDCs align with the state's requirements under the CLCPA and other state and local climate and clean energy goals and targets.

New York's CLCPA, one of the nation's most ambitious climate change laws, established the following targets for the reduction of GHG emissions:[3]

- 40 percent reduction in GHG emissions from 1990 levels by 2030
- 85 percent reduction in GHG emissions from 1990 levels (absolute) and net-zero GHG emissions by 2050
- 70 percent of the state's electric supply from renewable sources by 2030
- 100 percent of the state's electric supply from zero-emissions sources by 2040
- 9,000 megawatts of offshore wind by 2035
- 6,000 megawatts of distributed solar by 2025
- 3,000 megawatts of energy storage capacity by 2030

Achievement of these goals will require substantial investment and deployment of clean energy technologies, including wind and solar projects, electric vehicles, and energy efficiency measures. By providing a rigorous, consistent, and transparent approach to quantifying GHG emissions, the framework allows stakeholders to evaluate different gas supply- and demand-side options and assess how specific LDC plans will affect the state's ability to meet its obligations under the CLCPA.

The framework described here only addresses quantification of life cycle GHG emissions. There are other important aspects of gas supply planning, such as assessments of LDC and customer costs and system reliability. The methodology described here is intended to be used in conjunction with these other assessments to give a more complete picture of LDC gas supply decision making in the context of state goals to achieve significant reductions of carbon emissions, while assuring New Yorkers have reliable access to affordable energy.

New York's Gas Planning Proceeding

On March 19, 2020, the New York Public Service Commission (PSC) initiated the "Proceeding on the Motion of the Commission in Regard to Gas Planning Procedures" ("Proceeding") to consider issues related to the planning procedures used by New York's natural gas local distribution companies (LDCs)[4] due to the invocation of moratoria on new service connections by two LDCs and due to the implications of the CLCPA.[i]

In January 2019 Con Edison announced a moratorium on new firm gas services in most of Westchester county.[ii] Con Edison noted that the demand for natural gas is outpacing supply on the coldest days due

[3] The CLCPA's GHG emission reduction targets are defined using CO_2-equivalent (CO_2-e) with a global warming potential (GWP) measured over an integrated twenty-year time frame (GWP_{20}), as defined by the IPCC.
[4] The seven LDCs are: Central Hudson Gas & Electric, Consolidated Edison (Con Edison), National Grid (KeySpan Energy Delivery-NY [KEDNY] and KeySpan Energy Delivery-Long Island [KEDLI]), National Fuel Gas Corporation, New York State Electric & Gas (NYSEG), Orange and Rockland (O&R), and Rochester Gas and Electric (RG&E).

to oil to gas conversions, preference for natural gas use in new building construction projects, and constraints on interstate pipelines that bring natural gas to customers in Westchester County. To address the supply-demand imbalance, and help existing customers reduce the amount of gas they use, Con Edison is implementing non-pipeline solutions to reduce reliance on natural gas. Then, in May 2019, National Grid announced a moratorium for new firm service connections, or requests for additional firm load from existing customers in Brooklyn, Queens, and on Long Island. Based on a settlement agreement with the State of New York in November 2019, National Grid resumed connecting natural gas service to customers for the next two years and agreed to invest in new energy efficiency, gas conservation measures designed to relieve stress on the system and reduce peak-day gas usage. The PSC required National Grid to develop a Long-Term Capacity Report to address the long-term capacity constraints affecting its operations.

The PSC observed that the manner in which moratoria are managed can “create or mitigate hardship and inequity,” and stated that current practices have not kept pace with recent developments and demands on energy systems. The PSC has stated that the aim of the planning proceeding is to improve planning and operational practices in a transparent and equitable way, minimizing infrastructure investments while maintaining safe and reliable service, and ensuring that natural gas utilities’ planning is aligned with the state’s climate policy.

Finding that these moratoria could “create or mitigate hardship and inequity,” the PSC required LDCs to each develop a Long-Term Capacity Report to address the long-term capacity constraints affecting their operations. The PSC stated that current practices have not kept pace with recent developments and demands on energy systems. Ultimately, the PSC hopes the proceeding will improve planning and operational practices in a transparent and equitable way, minimizing infrastructure investments while maintaining safe and reliable service.

In the Proceeding, the LDCs have submitted filings addressing four interrelated issues: (1) the identification of “vulnerable locations” in which there is an expected/forecasted future imbalance in the supply of and demand for natural gas; (2) reliance on supply- and demand-side solutions to meet demand; (3) management of moratoria conditions when such events are contemplated (in their joint filing, the LDCs declared moratorium should be a last resort option); and (4) the design of a “modernized” gas system planning process.

In their joint filing,[iii] the LDCs outlined six principles to guide the Natural Gas System Planning Process:

1. Ensure safety and reliability of gas delivery service while supporting New York State’s environmental, economic, and other policy goals;
2. Meet anticipated demand by customers by providing a range of supply- and demand-side resources, including electrification, energy efficiency, demand response, and other stakeholder solutions (*described in further detail in the following sections*);
3. Protect information confidentiality and preserve competitive procurement process;
4. Be transparent and meaningfully engage stakeholders, clearly communicating changes that will result;
5. Guide LDCs in development of periodic long-term Gas System Resource Plans that reflect future demand, supply- and demand-side options, market conditions, and policy goals; and

6. PSC should coordinate the filing of LDC Gas System Resource Plans with other filing requirements.

The utilities submitted three analyses: (1) supply and demand analysis to identify vulnerable locations; (2) supply and demand analysis to cover the entire service territory; and (3) identification of demand-side and other measures intended to address supply/demand imbalance (*further discussed in the following* Supply-Side Strategies *and* Demand-Side Strategies *sections)*.

In addition to the independent and joint LDC filings, NRDC and Pace Energy and Climate Center contributed important stakeholder input. NRDC posed that in a CLCPA-compliant future with declining fossil gas consumption, gas utilities will simultaneously face two potentially competing challenges: (1) maintaining rates that are low enough to avoid accelerating defection away from gas service— which, if unmanaged, could leave remaining customers shouldering tremendous costs; and (2) aging pipes that leak or pose safety risks. NRDC recommended critically examining conventional gas investments, requiring open and integrated energy planning, and revisiting the obligation to provide gas service in light of socialized costs, among others.[iv] Pace offered a Zero Net Gas Framework, which does allow for new gas uses (unlike a moratorium) as long as it is paired with demand reductions within a particular system (i.e., any proposed increase in gas demand is netted with a corresponding reduction in demand elsewhere in the system) as it is designed to halt growth of new gas demand and infrastructure.[v]

New York Department of Public Service (DPS) staff issued a gas system planning process proposal on February 12, 2021.[vi] The staff proposal notes that calculating and reporting the emissions of GHG emissions associated with all solutions, both supply-side and demand-side, is necessary for transparency when considering choices among alternative solutions. The proposal also notes that more work needs to be done to specify standards that should be applied to qualify a source as "renewable gas." Staff invites interested entities to work with Staff, the New York State Energy Research and Development Authority (NYSERDA), and the LDCs to propose such standards for future Commission consideration. The staff proposal also includes potential new incentives/earnings adjustment mechanisms (EAMs) for GHG emissions reductions such as methane emission reductions in natural gas supply chain and incentives for sourcing biomethane. Finally, DPS staff proposed that the Commission direct LDCs to begin filing long term plans every three years to initiate a modernized natural gas planning process, incorporates stakeholder input and reflects the State's GHG emissions reduction goals.

Supply-Side Strategies Proposed by LDCs

Renewable Natural Gas

Renewable Natural Gas (RNG) is the most heavily discussed supply-side solution. Actions proposed by the LDCs range from studying feasibility to actively exploring projects, establishing standards that would support market growth, and interconnecting projects with the gas network.

National Fuel "believes RNG should play a critical role toward achieving New York's GNG reduction goal" due to its unique methane reduction benefit and the fact it would utilize an existing infrastructure network.[vii] National Fuel concluded that its service territory has the ability to generate 14-17 percent of the state's total RNG potential (referencing its unique proximity to a large number of dairy farms and landfills in its service territory); the resource could displace between 15 and 92 percent of demand; and it is well positioned to accept RNG into its existing infrastructure system.

National Grid has partnered with New York City on two RNG projects at the Staten Island Landfill – which the City plans to shut down at the end of 2020 – and Newton Creek wastewater treatment center – which will become operational at the end of 2020. National Grid's filing indicates that RNG projects located in utility service areas have the potential to provide incremental gas supply without additional pipeline transportation infrastructure associated with traditional gas supplies. National Grid indicates that RNG projects seek long-term, fixed price purchase contracts to decrease the volatility of the projects' revenue streams (compared to selling their products into the spot market). National Grid states "that purchasing this sustainable gas to serve firm gas customers is consistent with the State's clean energy goals while supporting customers' energy needs."

Both Con Edison and Orange and Rockland have established standardized interconnection and purchase terms for anaerobic digestion facilities and have received inquiries from potential RNG project developers. Con Edison references that RNG could be particularly useful for industries for which electrification is not a viable option. Con Edison emphasized the resource's potential: "supply-side measures, other than RNG and hydrogen, are generally not aligned with long-term State and City climate change policy goals, face significant siting and permitting hurdles, and may be less reliable and more impactful to the environment than conventional gas pipeline infrastructure."[viii]

Liberty Gas has currently proposed RNG projects under consideration, some of which will be via direct injection from local dairies while others will involve trucked compressed RNG (CRNG) bringing in the resource from remote locations. As these CRNG stations will double as decompression and receiving stations for CRNG and compressed natural gas, Liberty Utilities projects they will add capacity, redundancy, and resiliency to its supply system.

Hydrogen

Two-thirds of the LDCs are currently studying the potential for blending hydrogen into the gas system. As mentioned in the RNG section, Con Edison believes that RNG and hydrogen are the most viable supply-side options for a number of reasons and currently participating in industry studies. National Fuel referenced its membership with the Low Carbon Resources Initiative (LCRI), a five-year collaborative effort facilitated by the Electric Power Research Institute (EPRI) and the Gas Technology Institute (GTI) that could cover a range of topics, including hydrogen.[ix] National Fuel describes its involvement stating that "while the Company is invested in exploring all of the LCRI's initiatives, a technology of particular interest to National Fuel currently is hydrogen/power-to-gas."[x] Lastly, National Grid referenced its support in a Stony Brook University study to explore the potential for blending hydrogen into the natural gas system. The study received funding from NYSERDA and is now underway.

Demand-Side Strategies Proposed by LDCs

Energy Efficiency & Demand Response

In their submissions detailing demand- and supply-side measures to address system imbalances, the New York LDCs highlighted an array of energy efficiency programs for residential, multi-family, small business, and commercial and industrial (including food services) customers. Free energy audits help customers better identify the greatest energy saving opportunities. Education and marketing initiatives, like Con Edison's Home Energy Reports and Smart Kids 5th grade curriculum, educate energy consumers of all ages. Rebates, sometimes presented through dedicated utility-operated marketplaces, reduce the upfront cost for a host of technologies, including gas and water heating alternatives, Wi-Fi enabled smart thermostats, LED lighting, and water-saving solutions. Partnerships with local public housing authorities can center the needs of low- and moderate-income customers by providing incentives for gas energy efficiency upgrades or large-scale weatherization initiatives.

National Grid serves as an example of innovative energy efficiency offerings: 1) a tiered incentive structure through which the total incentive paid to customer will increase when certain criteria are met as compared to traditional, flat energy efficiency incentives, and 2) the Pay for Performance pilot, where customers are rewarded for delivered energy savings on an ongoing basis as the savings occur rather than providing up-front payments on estimated energy savings. Going forward, National Grid will utilize the mapping and rating technology, MyHeat, to use thermal imaging to target customers with the greatest residential weatherization needs.

Utility approaches to demand response (DR) vary. All the LDCs besides Liberty mention interruptible rates through which they call upon customers to curtail usage when forecasts approach design day characteristics. On these days, customers switch to an alternative fuel source. This tool helps improve reliability in the short-term and avoid high infrastructure costs in the long-term. Through its Smart Solutions program, Con Edison developed a Gas DR Pilot, which it continues to make incremental changes to after each Winter Capability Season. The LDC also conducted DR test events with its Water Heater Control Pilot. O&R is implementing two Gas DR Pilot Programs, one for commercial and industrial customers who are not on interruptible rates and a thermostat control program for residential customers. In the first operational winter of National Grid's three-year Gas DR Pilot for its upstate territory, the utility achieved its sales target and exceeded its actual reduction target in the one test event by 10 percent with half of the customers delivering more reduction than they had committed to.

Fuel Switching & Electrification

Local Distribution Companies across the state are coordinating on the implementation of beneficial electrification programs – many of which include air source and ground source heat pump initiatives – through the New York State Clean Heat Program.[xi] Three LDCs referenced heat electrification targets through 2025: 1) National Grid's Upstate heat electrification target is 280,647 Gross MMBtu total savings, 2) O&R's heat pump target is 86,657 MMBtu, and 3) Con Edison's heat pump target is 1 million MMBtu.

Geothermal

As detailed in its submission, National Grid filed a proposal in its 2019 rate case for both upstate and downstate operations to expand a 2016 geothermal pilot through which the utility would study the conditions under which a geothermal shared loop could be installed instead of a gas main replacement. Through this pilot, customers would own the heat pumps and associated equipment while National Grid would own the geothermal loop (with the potential for shared loop systems serving multiple customers) to which they connect. Customers would pay a fixed monthly rate per ton of connected capacity, making costs straightforward for customers and potentially reducing cashflow impacts for National Grid. The expansion would build off of the 2016 pilot by including both vendor and customer outreach efforts, particularly expanding access to low- and moderate-income and commercial and industrial customers that have traditionally less access to geothermal systems.

Con Edison will also conduct at least two pilot programs to install geothermal loops in lieu of capital expenditures on main replacements. Customers connected to the loop would not have gas for any appliances or purposes. Additionally, Con Edison currently offers and NYSEG/RG&E have proposed to offer –through partnerships with NYSERDA – geothermal heat pump incentives that lower the upfront cost of the technology.

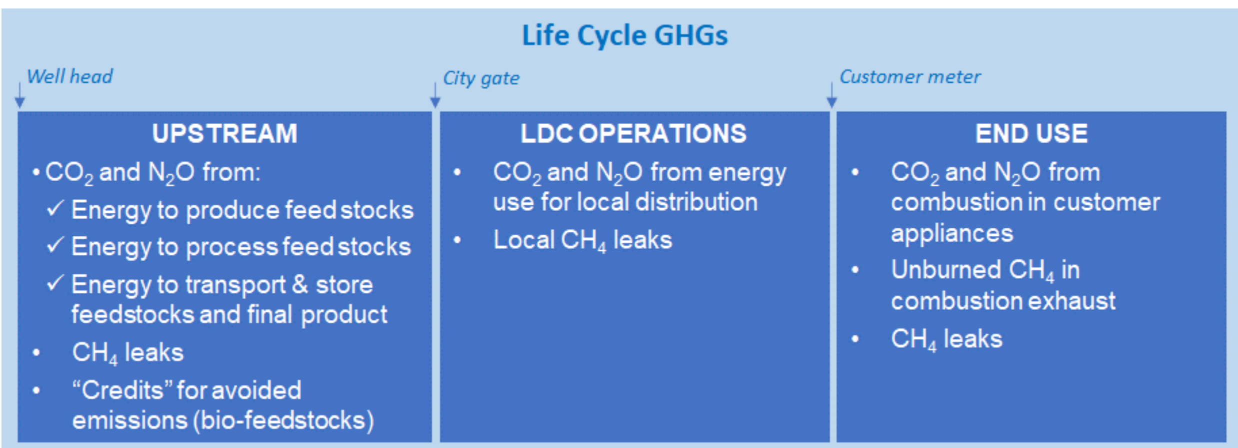
Principles for a Gas Company Climate Planning Framework

The Gas Company Climate Planning Framework is based on the following six core principles:

1. Account for all combustion-related GHG emissions and fugitive methane emissions.
2. Account for both supply- and demand-side options to manage and meet gas demand.
3. Use the most recent, publicly available data.
4. Identify and incorporate significant uncertainties.
5. Align the analysis with economy-wide GHG emission reduction targets under the CLCPA.
6. Monetize life cycle GHGs using the Social Cost of Carbon Dioxide, the Social Cost of Methane, and the Social Cost of Nitrous Oxide.

This framework uses a life cycle approach that accounts for GHGs emitted throughout the entire value chain of natural gas and other fuels, from production all the way through end use. For convenience, the framework follows the convention of dividing the fuel life cycle into three segments that are consistent with the data sources recommended for use in calculating emissions at each stage: 1) upstream, 2) LDC operations, and 3) end-use (see Figure 1).

Figure 1: Scope of Natural Gas Supply Life Cycle GHG Analysis



The upstream portion of the fuel life cycle encompasses all GHG emissions associated with production, processing, and long-distance transmission of natural gas and other fuels. This portion starts at the natural gas well-head and ends at the city gate, where ownership of the gas is transferred from a transmission pipeline company to the local LDC. The second section of the life cycle, LDC operations, encompasses GHGs associated with local distribution of natural gas or other fuels to customers. This section of the life cycle runs from the city gate to the customer meter. The last section of the fuel life cycle, end use, encompasses GHGs produced when the fuel is consumed by the customer, whether used to generate electricity, heat homes and businesses, or manufacture goods.

Each of the six core principles of the Gas Company Climate Planning Framework are reviewed in detail below.

1. Account for All Combustion-related GHGs and Fugitive Methane Emissions

Most natural gas delivered by LDCs to their customers is ultimately burned in appliances such as a furnace, boiler, turbine, or internal combustion engine. During combustion, the carbon in natural gas is oxidized, using oxygen from the air, to CO_2. During this process, some nitrogen in the combustion air is also oxidized—largely to nitrogen oxides (NOx) but also some to nitrous oxide (N_2O). In addition, some unburned methane (CH_4) is often emitted in the combustion exhaust. Because natural gas is composed of approximately 95 percent methane, methane is emitted throughout the natural gas value chain through the equipment and processes used for natural gas production and processing, as well as from leaks in pipelines and other equipment.

These three substances, CO_2, N_2O, and CH_4, are all GHGs that contribute to global warming. This framework therefore recommends accounting for emissions of all three gases across the entire fuel life cycle, whether from fuel combustion, leaks or other sources.

To sum total life cycle GHG emissions in CO_2-e, choices must be made about the appropriate global warming potential (GWP) to use. While CO_2, N_2O, and CH_4 are all GHGs, these gases differ from each other in two key ways: their ability to absorb energy (their "radiative efficiency"), and how long they stay in the atmosphere (also known as their "lifetime"). GWPs are a metric intended to allow comparisons of the climate change impacts of different gases, by measuring how much the energy the emissions of one ton of a gas will absorb over a given period of time, relative to the emissions of one ton of CO_2. The most common form, GWP_{100}, focuses on the climate impact of GHG emissions over 100 years. However, this form of GWP underestimates the warming effects of short-lived GHGs, such as CH_4, in the near term. Meanwhile, while GWP_{20} better reflects the warming effects of short-lived emissions, it ignores climate forcing impacts after 20 years, therefore underestimating the impact of pollutants such as CO_2 that remain in the atmosphere past this time frame.

The CLCPA mandates the use of GWP_{20}, as calculated by the United Nation's Intergovernmental Panel on Climate Change (IPCC). This convention is followed by this framework to ensure consistency with New York State policy and its climate planning process. Thus, consistent with the requirements of the CLCPA, all references to numerical GHG values (in CO_2-e) for specific fuels and gas supply options in this document are based on GWP_{20} (not accounting for climate feedbacks). However, it may be useful to calculate and report both GWP_{100} and GWP_{20} values, as has been recommended by certain stakeholders, to more adequately reflect and communicate the short- and long-term impacts of emissions.[xii]

2. Account for Both Supply-Side and Demand-Side Options to Meet Gas Demand

According to LDC filings in the NY Gas Planning Procedures Proceeding, most LDCs estimate continuing year-to-year increases in design day demand of between 1.5 and 2.5 percent in their service territories through 2025, with slightly lower but nonetheless continued annual increases through 2030.[5] This projected increase in design day demand is driven primarily by projected new building construction, as well as projected requests for conversion of existing buildings that currently use fuel oil for heating. However, for New York to succeed in achieving its long-term economy-wide emission reduction goals, total GHG emissions from natural gas use will need to decline significantly from current levels. Options

[5] Natural gas utilities are expected to provide a firm level of service to customers on an extreme cold weather day called the "design day", which is the peak day in the winter.

for LDCs to meet increasing demand while reducing GHG emissions can be broadly classified as supply-side and demand-side approaches.

Supply-side Options

On the supply side, LDCs could contract for more natural gas, to be delivered through existing, upgraded, or new pipelines. LDCs could additionally or alternatively contract to purchase alternative, lower-carbon energy sources to be blended with natural gas—either upstream or locally—for delivery to their customers. These alternatives include biomethane produced, in the near-term, from waste feedstocks such as landfills, wastewater treatment plants, and livestock manure. Additional alternatives, over the medium to longer term, include hydrogen produced from natural gas, biomethane and renewable electricity. Several organizations are also developing programs for differentiated natural gas with enhanced verified attributes, including lower life cycle GHGs, primarily due to lower CH_4 intensity. As these programs advance, this may become another viable option for LDCs to include in their resource supply mix.

Demand-side Options

There are two primary types of demand-side options that could be employed by LDCs in their long-term gas planning, each with a different purpose and effect. The first type encompasses efforts intended to reduce peak-day demand. An example would be a traditional demand response program, in which customers are provided a payment or incentive to reduce their natural gas use on peak days. Another example would be the local injection of liquefied natural gas (LNG) or compressed natural gas (CNG) into the LDC's distribution system on peak days, to increase supply while by-passing the transmission pipeline constraint.

The second type of demand-side option is intended to reduce *total* annual LDC customer demand for natural gas, not just on peak days. Examples include energy efficiency programs to provide natural gas customers with incentives to install more efficient gas appliances or to improve building insulation and/or windows to reduce total heating demand. Another example would be programs to incentivize individual natural gas customers to replace existing natural gas appliances with new appliances that use a different energy source (i.e., fuel switching), such as air or ground source heat pumps that use electricity rather than natural gas. More ambitious fuel switching options include the development of "district heating systems" that supply energy for space and water heating to multiple buildings via distribution of steam or hot water, with the steam/hot water produced by waste heat and/or large-scale geothermal systems.

3. Use the Most Recent, Publicly Available Data

To maximize transparency, ensure compatibility across different gas supply portfolios and among different LDCs, and maintain consistency across GHG inventories, the Gas Company Climate Planning Framework recommends, whenever possible, the use of peer-reviewed, publicly available emission factors to estimate emissions across the fuel life cycle.

Table 1 summarizes the public, peer-reviewed resources recommended for use in the Gas Company Climate Planning Framework. These resources and their utility within the framework are discussed in more detail in following sections of the report.

Table 1: Recommended Resources

Life Cycle Segment	Description of Data	Recommended Resource
Upstream	Natural gas: Emissions factors by production basin (g/MMBtu)	Life Cycle Analysis of Natural Gas Extraction and Power Generation, NETL
	Biomethane: Emissions intensity of certified biofuels pathways Emissions factors for biomethane produced from certain feedstocks[6]	LCFS, CARB GREET model, Argonne National Laboratory
	Hydrogen: Emissions factors for H_2 produced via SMR or electrolysis	LCFS, CARB GREET model, Argonne National Laboratory
LDC Operations	Emissions factors associated with LDC distribution of gas	GHGRP, Subpart W, EPA (based on Lamb et al., 2015)
		Weller et al. (2020)
		Additional academic research as necessary
End Use	Combustion emissions factors	MOVES model, EPA GHG Emission Factors Hub, EPA
	Emissions associated with fuel switching from natural gas to electricity	eGRID, EPA Power Trends, NYISO Or best available information on projected grid mix and emissions rates

In some cases, there may be unique or novel approaches to gas supply for which no public, peer-reviewed information is available. In that instance, LDCs will need to develop their own project-specific emission factors. When doing so, LDCs should provide enough information about the development of these emission factors to facilitate meaningful stakeholder review.

4. Identify and Incorporate Significant Uncertainties

Recent methane measurement campaigns by academic researchers have highlighted that significant uncertainties remain as to the amount of methane emitted across the entire natural gas supply system. Some "top-down" measurement studies have indicated that there may be significantly higher emissions

[6] Feedstocks covered include landfill gas as well as anaerobic digester sources including wastewater treatment plant sludge, food waste and livestock manure.

than indicated in EPA's national inventory, which is a "bottom up" analysis that uses many of the same baseline emissions factors that are recommended for use here.[7]

As such, the Gas Company Climate Planning Framework recommends that LDCs identify the relevant, significant uncertainties associated methane leakage assumptions used to develop the life cycle GHG inventory for each gas supply option and account for these uncertainties by using a range estimate for methane leakage that incorporates best available current information. The final estimated GHG inventory for each proposed gas supply portfolio would thus be presented as a central estimate, along with high and low estimates based on the range of potential methane leakage across the natural gas life cycle.

5. Align the Analysis with Economy-Wide GHG Emission Reduction Targets Under the CLCPA

Electricity is used throughout the natural gas life cycle to operate processing plants and run compressors that transport gas through the transmission and distribution systems. Electricity is also a potential direct substitute for natural gas in some end-use options (for example, electric heat pumps for space and water heating). As such, emissions from electricity generation will contribute to the overall life cycle GHG emissions profile of most if not all gas supply portfolios analyzed using the Gas Company Climate Planning Framework.

The CLCPA contains ambitious mandates for transformation of the electricity mix in New York—moving from approximately 30 percent renewables today to 70 percent renewables by 2030 and 100 percent zero-emissions resources by 2040. These targets have profound implications for the long-term natural gas planning process for two reasons. First, achievement of these goals would reduce natural gas demand for electricity generation in New York, which would offset some or all of the anticipated new demand for natural gas for space and water heating due to projected economic and population growth. Each LDC's baseline natural gas demand assumptions over the gas planning time horizon should account for this expected reduction in gas demand for electricity generation. Second, as renewable resources make up an increasing percentage of total generation over time, the average and marginal GHG emissions rates (pounds of CO_2e per megawatt-hour) for electricity generation will decline. The expected future decline in GHG emission rates should also be incorporated into the GHG analysis of LDC gas planning portfolios.

For transparency and consistency, the Gas Company Climate Planning Framework recommends that LDCs use long-term forecasts for annual natural gas demand for electric generation and annual electric grid GHG emissions intensity that are produced by the New York Independent System Operator (NYISO) and New York State agencies such as New York State Energy Research and Development Authority (NYSERDA) and the Department of Environmental Conservation (DEC), recognizing that there are regional differences in electricity load zones across the state.[8]

---

[7] "Bottom-up" methane emissions estimates calculate emissions based on equipment counts and default emission factors. In contrast, "top-down" measurements can be performed at a regional scale, such as flying an aircraft upwind and downwind of a study area.

[8] NYISO produces an annual Load & Capacity Data Report ("Gold Book"), annual Grid and Power Trends Report ("Power Trends") and other planning reports for generation and transmission planning; NYSERDA develops the

6. Monetize life cycle GHGs using the Social Cost of Carbon Dioxide, the Social Cost of Methane, and the Social Cost of Nitrous Oxide.

Ultimately, gas supply planning will need to balance the potentially competing goals of reducing GHG emissions while providing customers with access to reliable, safe, and affordable energy. In order to facilitate the integration of GHG goals into the more traditional economic aspects of gas planning, the Gas Company Climate Planning Framework recommends that LDCs calculate the monetized value of GHGs associated with gas supply portfolios using values for the Social Cost of Carbon.

The social cost of carbon—expressed as dollars per metric ton of GHG emissions ($/MT GHG)—assesses a value of the societal costs of climate change. By monetizing the value of gas system GHGs, the societal benefits of gas portfolios with lower GHG emissions can be appropriately compared to any additional costs associated with implementation of these scenarios (i.e., for purchase of low-carbon gas or incentives provided for fuel switching, etc.).

In December 2020, in accordance with requirements of the CLCPA, the New York State Department of Environmental Conservation (DEC) released guidance on the "Value of Carbon" (Guidance).[xiii] The Guidance establishes values for carbon dioxide, methane, and nitrous oxide based on an estimate of net damages incurred due to climate change and provides recommended guidelines for the use of these and other values by state agencies. DEC states that the guidance is intended for use by New York State agencies to aid in decision-making and makes clear that the guidance does not propose a carbon price, fee, or compliance obligation on any entity.

For transparency and consistency with state planning, the Gas Company Climate Planning Framework recommends that NY LDCs use the Value of Carbon produced by NY DEC.[9]

Recommended Methodology

This section further elaborates on the Gas Company Climate Planning Framework methodology for calculating the life cycle GHG emissions of any gas supply option. The methodology to conduct the analysis is as follows:

1. Use an activity factor and emission factors to calculate the emissions of each GHG (CO_2, CH_4, N_2O) at each stage of the life cycle.
2. Sum the emissions of each pollutant across the three life cycle stages (Upstream, LDC Operations, and End-Use).
3. Multiply total CH_4 and N_2O emissions by the appropriate GWP(s) to calculate their CO_2-equivalence (CO_2-e).

New York State GHG Emissions Inventory and DEC is required by the CLCPA to determine the NYS 1990 GHG emissions baseline.

[9] Relatedly, on January 20, 2021, President Biden issued an Executive Order reestablishing the federal Interagency Working Group on the Social Cost of GHGs and directed the working group to publish, within 30 days of the executive order, interim values for the Social Cost of Carbon, Methane, and Nitrous Oxide. The EO also directed the working group to provide recommendations, by no later than September 1, 2021, regarding "areas of decision-making, budgeting, and procurement" by the federal government where these values should be applied, and to publish final values by no later than January 2022. *See:* https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/20/executive-order-protecting-public-health-and-environment-and-restoring-science-to-tackle-climate-crisis/.

4. Sum the total CO_2, CH_4, and N_2O emissions to estimate total life cycle GHG emissions in CO_2-e (again, using the appropriate GWP(s)).
5. Use values for the Social Cost of Carbon Dioxide, Social Cost of Methane, and Social Cost of Nitrous Oxide to monetize the estimated total GHG emissions.

For the purposes of long-term gas planning, it is expected that LDCs will evaluate one or more portfolios of options to meet projected annual customer energy demand each year. Given that this framework is intended to cover a range of supply options beyond natural gas, it is appropriate to express this customer demand in energy rather than volumetric units. Thus, customer demand should be expressed as million British thermal units (MMBtu) of energy, rather than in terms of million standard cubic feet (MMSCF) of gas.[10] The "activity factor" for each option is the amount of total energy demand (MMBtu) supplied by that option each year. Emission factors for each pollutant at each stage of the life cycle should therefore be expressed as mass of emissions per unit energy delivered (grams per MMBtu, or g/MMBtu).

The Gas Company Climate Planning Framework's comprehensiveness and flexibility allows it to be used in several ways. For example, it can be used to compare different portfolios of gas supply options (to meet net annual total LDC energy demand), to compare specific discrete options, or to evaluate the effect of a proposed portfolio on state GHG reduction goals.

Different gas supply options will have significantly different GHG emissions factors for each stage of the life cycle. For example, depending on the feedstock used to produce it, upstream GHG emissions (g CO_2e/MMbtu) from hydrogen could be significantly higher than upstream emissions from natural gas, but zero emissions are emitted from the end-use combustion of hydrogen, resulting in the potential of a net reduction in total life cycle GHG emissions. As a second example, the emissions impact of transporting and combusting biomethane (i.e., LDC operations and end-use combustion) are equivalent to those associated with supplying and combusting natural gas, but net upstream GHG emissions from biomethane vary and could be negative (for example, if reduced venting resulted in a net reduction in life cycle GHG emissions compared to natural gas).

For energy efficiency programs, associated GHG emissions are zero for each stage of the life cycle for the reduction in demand for energy. For options that result in fuel switching from natural gas to electricity (i.e., heat pumps), end-use combustion emissions are zero, although there are upstream emissions associated with the generation of electricity (however, emissions factors for electricity generation are expected to decline over time as renewable sources supplying the New York electric grid increase over time).

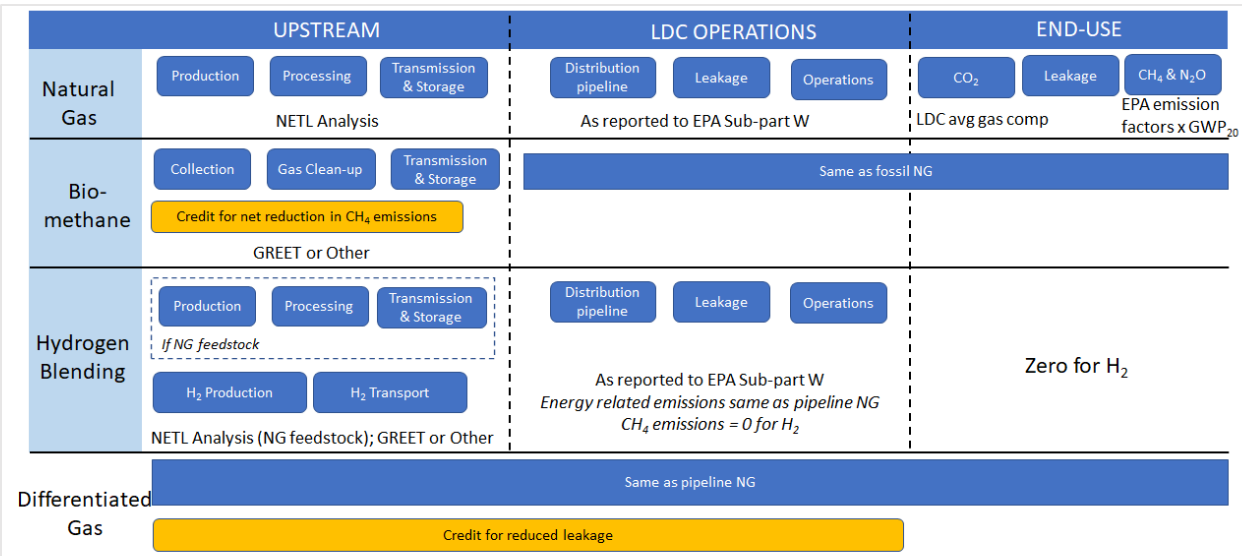
This section discusses the specific methodologies recommended for calculating life cycle GHG emissions associated with the most common supply-side and demand-side gas supply options that might be included in a gas supply portfolio, as well as recommended data sources for developing relevant emission factors.

[10] One BTU is the amount of energy required to raise the temperature of a pound of water by 1 °F at atmospheric pressure. Fossil natural gas typically contains approximately 100,000 btu per 100 standard cubic feet (higher heating value), depending on composition. Natural gas is also measured in therms; one therm of gas is equal to approximately 100 cubic feet or 100,000 Btu of energy.

Supply-Side Options: Natural Gas and Low-Carbon Alternatives

Over the next 20 years, the most likely options for commodity energy to be supplied by New York LDCs through existing gas distribution networks are conventional natural gas, biomethane, and hydrogen blended with these other fuels. See Figure 2 for a summary of the different emission sources that should be accounted for in each section of the life cycle for these fuels and recommended data sources for development of relevant emission factors.

Figure 2: Life Cycle GHG Analysis of Supply-side Options



Natural Gas

For natural gas, baseline upstream emission factors (g/MMbtu) can be derived from an analysis conducted by the National Energy Technology Laboratory NETL).[xiv] This analysis identifies differences in upstream emissions from gas produced in different production basins.[11] If an LDC procures gas from specific basin(s), it would be appropriate to use weighted average emission factors based on the percentage of gas delivered to the LDC from each basin; otherwise, average emissions factors representing U.S. production can be used. Natural gas utilities should strive for consistency with New York State agency GHG inventory methodologies, including NYSERDA's New York State Oil and Gas Sector Methane Emissions Inventory[xv] and NY DEC Part 496 (for 1990 baseline emissions estimation).[xvi]

Baseline emissions factors (g/MMbtu) for LDC operations to locally distribute natural gas can be derived from data reported by the LDC to EPA's GHG Reporting Program (GHGRP), subpart W.[xvii] These emission factors will vary by LDC based on system characteristics.

CO_2 emission factors (g/MMbtu) from end-use combustion of natural gas can be calculated based on an LDC's average gas composition (percent of CH_4 and other gases), the carbon content (by weight) and energy density of each gas. Emissions factors can also be calculated using GWP_{20} or GWP_{100}; the CLCPA requires the use of GWP_{20} although both metrics may provide value. Emission factors for CH_4 and N_2O

[11] While an increasing share of New York's natural gas comes from Pennsylvania, additional supply basins include Gulf Coast, East Texas, Anadarko, Arkoma, and Canada.

from end-use combustion of natural gas are available from EPA's Emission Factors for GHG Inventories.[xviii] See Table 2 for GHG emission factors for fossil natural gas.

Table 2: End-Use Combustion GHG Emission Factors, Natural Gas

Combustion Emissions	CO_2	CH_4	N_2O
	kg/Mmbtu		
Natural Gas *(Residential and Commercial)*	53.06	0.001	0.0001

Source: U.S. EPA Emissions Factors for GHG Inventories (2020)

To calculate CH_4 and N_2O emissions in terms of their CO_2-equivalence, the CLCPA directs the use of GWP_{20} values developed by the IPCC. In its most recent report (Fifth Assessment), the IPCC provides two sets of GWP_{20} estimates—those that account for climate-carbon feedbacks (CCF) and those that do not (non-CCF) (data is similarly provided for GWP_{100} estimates). In regulations codifying the state's GHG emission reduction limits, NY DEC incorporates IPCC's non-CCF GWP_{20} estimates by reference.[xix] Thus, to align with New York state policy, this framework recommends the use of non-CCF GWP_{20} estimates. According to the IPCC's Fifth Assessment, when not accounting for climate-carbon feedbacks, the GWP_{20} of CH_4 is 84 and the GWP_{20} of N_2O is 264.[xx] However, as previously discussed, entities may find it helpful to calculate and report on the GHG emissions using both GWP_{20} and GWP_{100} in order to better communicate the short- and long-term climate impact of GHGs.[12]

As discussed in the section on Gas Company Climate Planning Framework principles, there are significant uncertainties regarding total CH_4 emissions emitted across the natural gas life cycle (ranging from upstream to downstream operations, leaks, and end use). For example, leakage in end use occurs during start up and shut down or from poor maintenance. As such, the baseline CH_4 emission factors derived from the NETL analysis (upstream) and from LDC reporting to the GHGRP (LDC Operations) may underestimate actual CH_4 emissions from production and delivery of conventional natural gas. Thus, the Gas Company Climate Planning Framework recommends using a range estimate for CH_4 emission factors, including from upstream, LDC operations, and end use to account for this uncertainty.

There have been significant efforts to better understand and quantify methane emissions from the natural gas supply chain in recent years. In the natural gas distribution segment, the assumptions used to estimate methane emissions were, until recently, based on a 1996 study by the Gas Research Institute and EPA (GRI/EPA) that used 1992 data. In 2015, a new study by Lamb et al. was published with data based on direct measurements of methane emissions from underground mains and services and other sources in the natural gas distribution system.[xxi] The activity factors (leaks/mile) and emissions factors (g CH_4/minute/leak) developed from these data were overall substantially lower than those from the GRI/EPA study.

In 2016, in response to the new data, EPA updated the GHG Inventory methodology to adopt the emissions factors from Lamb et al. for specific distribution sources, including mains. The revised emissions factors for mains were applied to all years beginning in 2011 and onward; the original GRI/EPA

[12] For reference, according to the IPCC's Fifth Assessment, the GWP_{100} of CH_4 is 28 and the GWP_{100} of N_2O is 265 (again, not accounting for climate-carbon feedbacks).

factors were maintained for 1990 through 1992, and emissions factors for these intermediary years (1993-2010) were calculated using linear interpolations of the old and new emission factors.

More current research indicates that the EPA GHG Inventory likely underestimates methane emissions from gas distribution systems. For example, a June 2020 study, *A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems*, by researchers at Colorado State University and EDF ("Weller et al.") presented new data on methane leakage from natural gas distribution mains.[xxii] The authors used data from advanced mobile leak detection (AMLD) surveys conducted using vehicle-mounted methane detectors and taken across four urban areas; the study also used pipeline data from the Pipeline and Hazardous Materials Safety Administration (PHMSA) and local utilities to develop new activity and emissions factors for distribution mains. Overall, the study found that the activity and emissions factors currently used in EPA's GHG Inventory underestimate actual methane emissions.

To account for this uncertainty, the Gas Company Climate Planning Framework recommends using a range estimate for CH_4 emission factors, including from upstream, LDC operations, and end use.

Biomethane

Biomethane is derived from biogas produced by anaerobic digestion or thermo-chemical conversion of biomass. In anaerobic digestion, microorganisms break down organic material in a zero-oxygen environment, producing methane and carbon dioxide. Biogas can also be created using thermo-chemical conversion, in which woody biomass, crop residuals, or dedicated energy crops are processed at high temperatures in low-oxygen conditions to break down the material at the molecular level without combustion. The resulting hydrogen and carbon monoxide gases are then converted to methane and carbon dioxide using a process called methanation.

In the near term, the most common sources of biomethane available to LDCs include landfills and wastewater treatment plants, followed by dairy farms and other livestock operations (with biogas collected from manure ponds), all of which would produce biogas via anaerobic digestion. Food waste can also be diverted from landfills to enhance biogas production by anaerobic digesters at dairy or wastewater treatment plants.

Raw biogas can often be used locally to produce on-site electricity or heat, with minimal processing. However, to be delivered to customers by an LDC through their distribution system, it must be processed or "upgraded" to meet pipeline quality standards, so that it can be used interchangeably with conventional natural gas. The primary upgrading step is to remove most of the CO_2.

When calculating GHG emissions associated with LDCs supplying biogas to customers, conventional natural gas emission factors can be used for CO_2, CH_4, and N_2O emissions for LDC operations (including estimates of CH_4 leakage) and for end-use. This is because biomethane must meet the same pipeline quality standards as conventional natural gas. However, upstream emission factors will be unique and will vary depending on the source of the biomethane.

The exact climate impact of biomethane depends, in large part, on 1) whether its use (in replacement of conventional natural gas) results in a net reduction in methane emissions and 2) the amount of fossil CO_2 emitted to process and deliver the biomethane to the pipeline. Biomethane requires upstream energy inputs (and resulting GHG emissions) for the collection and processing of biogas, as well as the transport of biomethane. However, many sources of biogas currently allow the biogas (containing CH_4) to vent to the atmosphere. When previously-vented biogas is collected, processed, and used beneficially as biomethane to displace conventional natural gas, this venting will often result in a net reduction in GHG emissions, and a "credit" can be generated. Thus, net upstream GHG emissions (g/MMbtu) of biomethane from previously vented sources are therefore usually negative, and net life cycle GHG emissions are lower than emissions from natural gas. Most U.S. landfills are required by EPA regulations to collect and flare biogas, so biomethane from landfills is given upstream credit for reducing CO_2 from flaring. However, diverting the biogas from a flare—combined with the emissions associated with processing and transporting the biomethane—can result in comparatively higher methane emissions, offsetting the CO_2 credit and potentially resulting in a detrimental climate impact. Similarly, biomethane derived from any organic feedstock that does not currently result in methane emissions (such as woody biomass, crop residuals, or dedicated energy crops) can result in an increase in methane emissions if these feedstocks are thermo-chemically or otherwise converted to methane and therefore result in a detrimental climate impact.

There are several data sources that can be used to develop upstream emission factors for biomethane. The first is Argonne National Laboratory's GREET model, which includes upstream emission factors for biomethane produced from landfill gas as well as anaerobic digester sources, including wastewater treatment plant sludge, food waste and livestock manure.[xxiii] The other data source is California's Low Carbon Fuel Standard (LCFS) pathway certified carbon intensities for various commercial biomethane projects that qualify to participate in the LCFS program.[xxiv] The California Air Resources Board requires participating companies to generate a life cycle GHG analysis for their specific fuel "pathway," from production to delivery in California, and has developed several "calculators" for this purpose, which use a modified version of GREET to determine GHG emissions across the fuel lifecycle for biomethane produced by landfills, wastewater treatment plants, digestion of organic (food and yard) waste, or from dairy and swine manure.[xxv] See Table 3 for a summary of the life cycle GHG emissions (g CO_2e/Dekatherm, using GWP_{20}) for biomethane produced from different sources; this figure includes the GREET value for each biomethane source, as well as the range of values for the certified biomethane pathways participating in the California LCFS program.

Table 3: Life Cycle GHG Emissions from Biomethane Feedstocks

Biomethane Emissions	GREET Life-Cycle	LCFS Certified CI
	[g CO2-e/Dth]	
Landfill Gas	25,404.1	39,174.1 - 70,867.9
Livestock Manure	-275,187.7	-268,975.1
Wastewater Sludge	-90,363.6	8,176.7 - 32,622.2
Food Waste	-372,471.0	-24,192.4

Source: GREET model and LCFS certified pathways.

Hydrogen Blending

The U.S. currently produces 10 million metric tons of hydrogen each year. Most of this hydrogen is produced from natural gas via steam methane reformation (SMR); hydrogen can also be produced from water using electricity (electrolysis). Hydrogen is currently used in various industrial processes, including petroleum refining, chemical manufacturing, and food and fertilizer production.

Hydrogen can also be burned to produce heat, which produces only water with no CO_2 emissions (although combustion modifications are needed to minimize NOx emissions). As such, there is growing interest in the use of hydrogen as a low-carbon fuel to supplement or replace natural gas for space and water heating and for production of industrial process heat. While existing transmission and distribution networks are not suited for moving pure hydrogen, current research indicates that up to 20 percent hydrogen (by volume) could be blended with fossil natural gas and/or biomethane and delivered by LDCs to their customers using existing infrastructure.[13]

For GHG life cycle analysis, end-use combustion GHG emissions from hydrogen are zero. Emission factors for CO_2 and N_2O from LDC Operations to distribute hydrogen are the same as for distribution of natural gas, since these emissions come from energy inputs (i.e., electricity to run compressors), but CH_4 emissions from LDC Operations will be zero for the hydrogen portion of the blended gas mix.

Upstream emissions from production of hydrogen will vary depending on feedstock and production method. If the hydrogen is produced from natural gas via SMR, there will be upstream GHG emissions from production and processing of the fossil natural gas feedstock, as well as additional emissions from the energy inputs for the SMR process and CO_2 that is released during the SMR process. If carbon capture and storage is integrated into the SMR process, the reduced CO_2 emissions should be accounted for. There may also be additional GHG emissions associated with transport of the hydrogen from the production location to the point of injection to the LDC system; this transport could be by dedicated pipeline or by truck or rail (compressed or liquid hydrogen).

If hydrogen is produced from water by electrolysis, there will be upstream GHG emissions from generation of the necessary electricity, and there may also be additional GHG emissions associated with transport of the hydrogen from the production location to the point of injection to the LDC system. If hydrogen is produced using electrolysis powered by zero-emitting electricity (i.e., renewable or nuclear sources), then the corresponding GHG emissions associated with production are zero (or near-zero).[14]

Similar to biomethane, there are several data sources that can be used to develop upstream GHG emission factors for hydrogen. The first is Argonne National Laboratory's GREET model,[xxvi] which includes upstream emission factors for hydrogen produced 1) from North American natural gas via SMR and 2) via electrolysis, using electricity from different grid sources (whether Northeast Power Coordinating Council, Inc. (NPCC) grid electricity (which includes New York) or using renewable electricity. The other data source is the LCFS pathway certified carbon intensities for various commercial hydrogen projects that qualify under California's Low Carbon Fuel Standard programs.[xxvii]

[13] While existing transmission and distribution networks are not suited for moving pure hydrogen, current research indicates that up to 20 percent hydrogen (by volume) could be blended with fossil natural gas and/or biomethane and delivered by LDCs to their customers using existing infrastructure.
[14] While electricity from renewable or nuclear sources does not generate emissions, there may be emissions earlier on in the life cycle process that are associated with construction of the generation facility and/or the electrolyzer.

See Table 4 for a summary of the life cycle GHG emissions (g CO_2e/Dekatherm, using GWP_{20}) for hydrogen produced from different sources; this figure includes the GREET value for each hydrogen source, as well as the range of values for the certified pathways participating in the California LCFS program.

Table 4: Life Cycle GHG Emissions from Hydrogen Feedstocks

Hydrogen Emissions	GREET Life-Cycle [g CO2-e/Dth]	LCFS Certified CI
North American Natural Gas (SMR)	100,151.9	110,917.7 - 175,012.1
North American Natural Gas with Carbon Capture (SMR w/ CCS)	-25,589.8	N/A
NPCC Grid Mix (Electrolysis)*	97,919.8	173,514.0
100% Renewables Grid Mix (Electrolysis)	12,114.8	0.0 - 11,088.6

** LCFS value is based on average California grid electricity*

Although the GHG emissions associated with hydrogen produced via clean energy technologies (i.e., an electrolyzer using renewable energy) are zero or near-zero, hydrogen itself is an indirect GHG. While further research is needed, the latest science suggests a GWP_{100} of 10, which equates to a GWP_{20} of 36, given hydrogen's atmospheric lifetime of 2.5 years.[xxviii] The magnitude of this climate impact depends on the rate of hydrogen leakage from storage, delivery, and dispensing systems. Current estimates of leakage range from 0.3 percent to 10 percent.[xxix] Leak rates around 1 percent would likely yield minor climate impacts, although leak rates of 10 percent could significantly undermine the climate benefits of increased use of low-carbon hydrogen. At this time, this framework does not recommend incorporating the indirect climate impacts resulting from hydrogen leakage, given the need to refine leakage estimates and the resulting climate impacts. However, future versions may include this potentially important component.

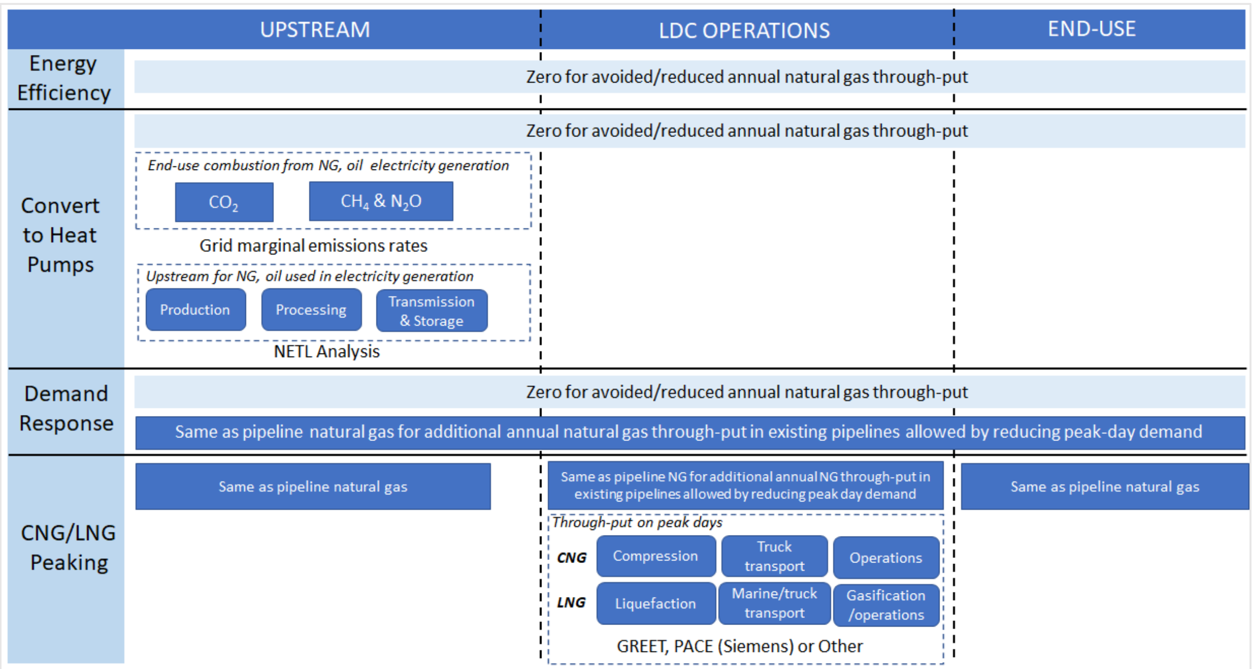
Demand-Side Options: Energy Efficiency, Demand Response, and Fuel Switching

There are several ways that New York LDCs can affect annual net customer energy demand. These strategies can be divided into two types: those designed to address supply constraints on peak-days, and those designed to reduce total annual customer energy demand. Strategies to address peak-day constraints include demand response programs and CNG or LNG peaking. Strategies to reduce total annual customer demand include energy efficiency programs and fuel switching programs.

Energy efficiency programs might offer incentives for customers to replace windows, add building insulation, or replace old natural gas appliances with new, more efficient appliances. Fuel switching programs could incentivize replacement of gas furnaces with air-source or ground-source heat pumps, thus switching from natural gas to electricity for space and/or water heating. These programs could target both existing buildings and new construction.

See Figure 3 for a summary of the different emission sources that should be included in each section of the life cycle for each of the most common demand-side options, and recommended data sources for development of relevant GHG emission factors.

Figure 3: Life Cycle GHG Analysis of Demand-side Options



Energy Efficiency

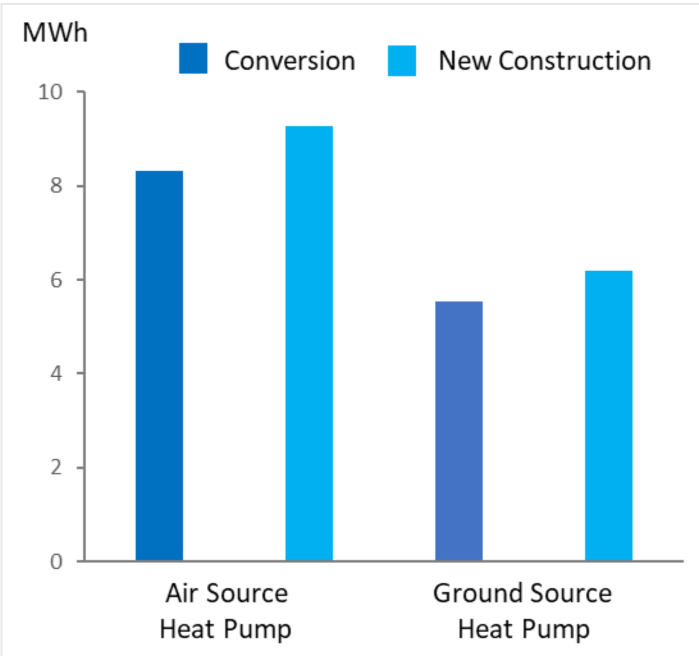
Energy efficiency programs reduce total annual natural gas demand compared to "baseline" projected demand without the program in place. GHG emissions from avoided gas use are zero. For the purposes of the Gas Company Climate Planning Framework, the amount of avoided energy use attributed to the energy efficiency program is the "activity factor" and the emissions factors applied are zero for all pollutants in all stages of the life cycle.

Fuel Switching Programs

Like energy efficiency programs, programs that incentivize existing or new LDC customers to switch from natural gas to another fuel for space and water heating result in a net reduction in natural gas demand, and the GHG emissions associated with this "avoided" demand are zero. However, the life cycle emissions analysis must account for all emissions associated with the alternative fuel source. In the case of electrification, the life cycle analysis should account for all GHG emissions from electricity generation to power the replacement heat pumps.

The amount of electricity required to replace the avoided gas demand can be calculated based on the relative efficiencies of natural gas appliances and heat pumps. However, this calculation requires assumptions about the mix of gas appliances to be replaced (existing buildings, new construction) as well as the mix of heat pump technologies to be installed (air-source, ground-source). See Figure 4 for an illustrative example of the amount of electricity (MWh) required to replace 100 MMBtu of natural gas used for residential and commercial space heating. This figure assumes that existing buildings will have older gas furnaces with 80 percent efficiency, while new buildings would have more efficient gas furnaces, with 95 percent efficiency. It also assumes that air source heat pumps have a coefficient of performance (COP) of 3.0, while ground source heat pumps have a COP of 4.5.[15] These efficiency and COP values are typical of existing and new equipment commercially available in New York.[xxx] Depending on the mix of buildings to be converted and the type of heat pumps to be installed, heat pumps would typically consume 5.5 to 9.3 MWh of electricity for every 100 MMBtu of natural gas displaced.

Figure 4: Electricity Required to Replace 100 MMBtu of Natural Gas for Space Heating

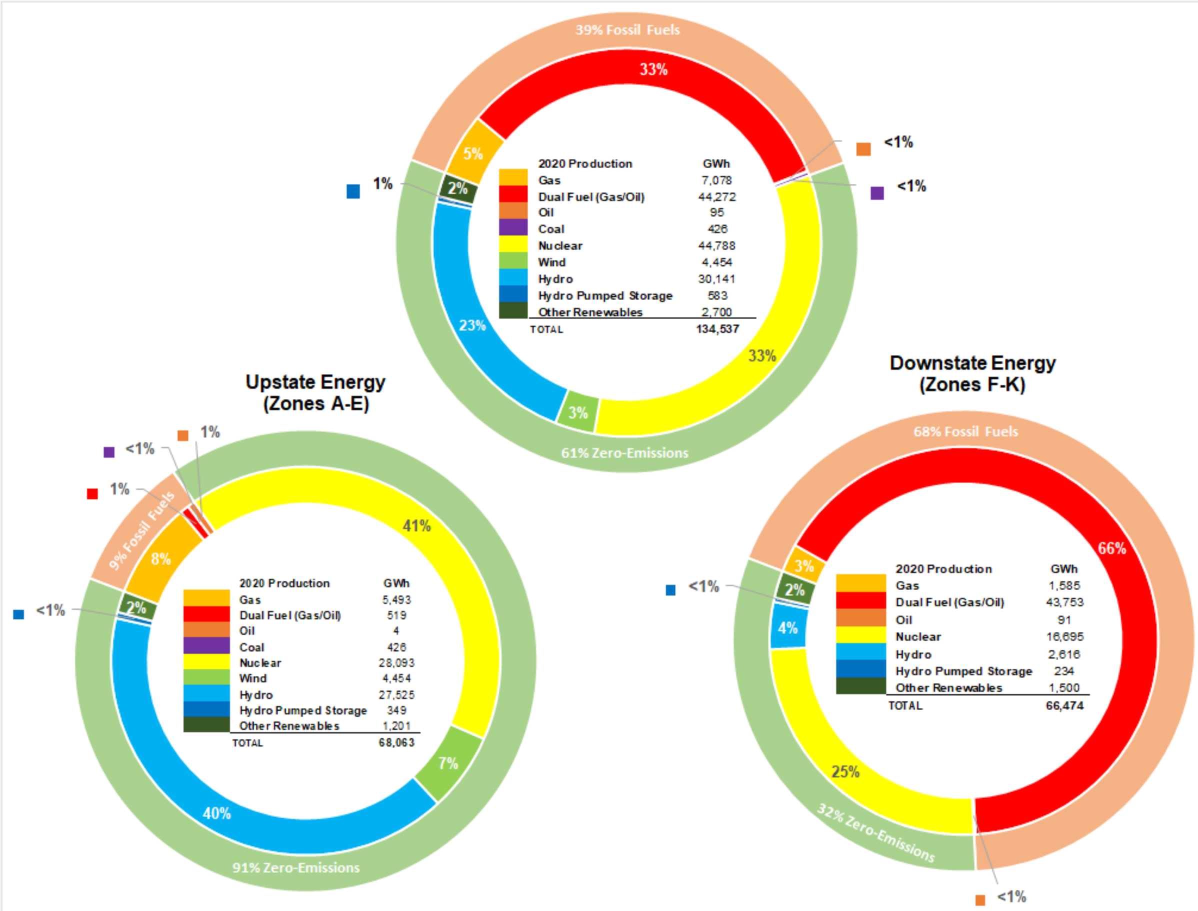


Emissions from electricity generation include stack emissions (CO_2, CH_4, and N_2O) from burning hydrocarbon fuels (i.e., natural gas, oil) in thermal or turbine power plants, as well as upstream emissions from production and delivery of these hydrocarbon fuels to the power plants.

The annual average fuel mix for electricity generation in New York in 2019 was approximately 33 percent dual fuel (natural gas and oil), less than 5 percent oil, less than 5 percent coal, and 58 percent zero-emitting sources (nuclear, hydro, and wind).[xxxi] However, this mix varied depending on load zone (for example, Upstate NY (Zones A-E) vs. Downstate NY (Zones F-K)). In Downstate NY, for example, fossil fuels accounted for approximately 69 percent of generation in 2019, with only 29 percent from zero-emitting sources. Figure 5 below provides a snapshot of the fuel mix for the entire state, upstate, and downstate, according to NYISO.

[15] COP is a measure of the useful heat output of the system (kWh) divided by electrical energy input (kWh). The higher the COP the less input energy required to generate the same amount of heat (i.e. the system is more efficient).

Figure 5: New York State Electricity Production by Fuel Type (2019)



Source: MJB&A analysis of NYISO 2020 Power Trends Report.

For the purposes of estimating GHG emissions from fuel switching from natural gas to electricity, the marginal generation mix is more relevant than the average generation mix of existing demand—in particular, the marginal generation mix during the winter heating season when natural gas demand peaks. Marginal generation and associated emissions correspond with electric generating facilities that are brought online as necessary to meet demand, thus providing a more accurate estimation of the net emissions effect of fluctuating electricity demand.

NYSERDA has adopted the NYS Public Service Commission's recommendation in its January 2016 Order Establishing the Benefit Cost Analysis Framework that New York's GHG emissions factor methodology shift from an average grid emission profile to a marginal grid emission profile.[xxxii] For comparison, the average electricity grid emissions rate in New York in 2019 was approximately 380 pounds CO_2e/MWh;[xxxiii] NYSERDA applies a marginal grid emission factor of around 1,100 pounds CO_2e/MWh.[xxxiv]

EPA's Emissions & Generation Resource Integrated Database (eGRID) also provides estimates for non-baseload emission rates by North American Electric Reliability Corporation (NERC) sub-regions, including Long Island, New York City/Westchester, and upstate New York.[xxxv] These rates correspond with generating facilities that are effectively "on the margin," or facilities that that are dispatched to address demand exceeding that met by baseload facilities. Table 5 displays non-baseload generation and associated emission rates within New York regions of NPCC.

Table 5: NPCC Non-Baseload Emission Rates (end-use emissions only)

	Non-Baseload Generation (GWh)					CO2e Rate
Region	Gas	Biomass	Coal	Oil	Total	lb/MWh
Downstate NY	17,751	109	0	107	17,968	1,104
NYC/Westchester	*12,557*	*50*	*0*	*10*	*12,617*	*1,019*
Long Island	*5,194*	*60*	*0*	*97*	*5,351*	*1,306*
Upstate NY	13,158	450	427	262	14,297	896
Total	**30,909**	**559**	**427**	**370**	**32,265**	**1,012**

Source: MJB&A analysis of U.S. EPA EGRID, NPCC. See eGRID 2019 Data File, https://www.epa.gov/egrid.

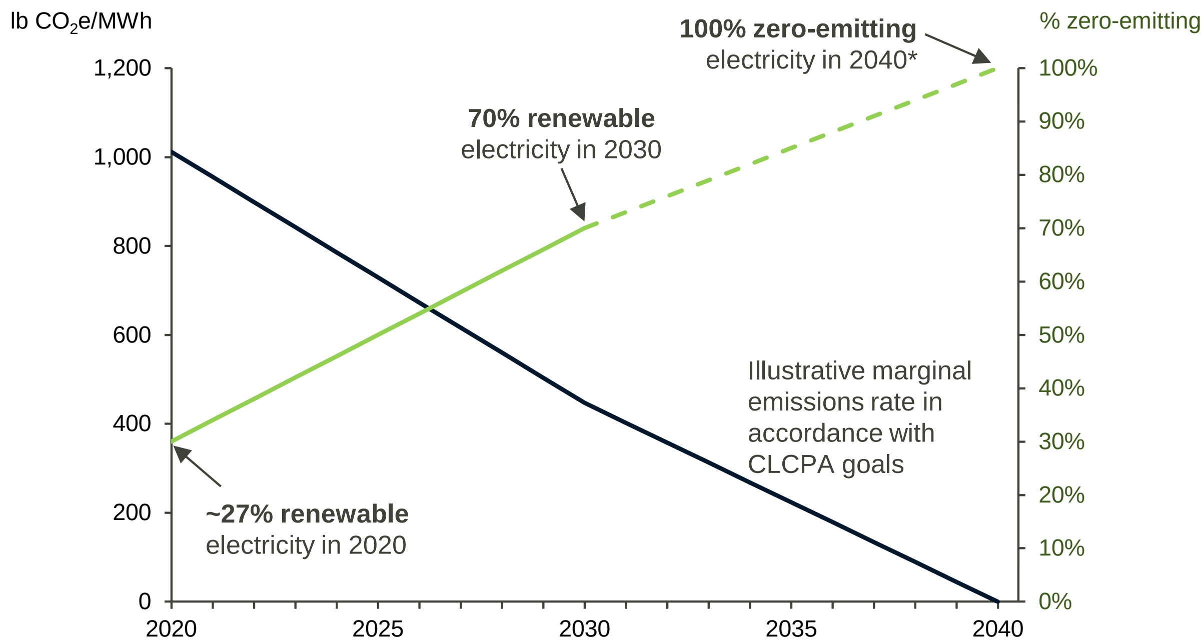
To estimate generation emissions associated with fuel switching from natural gas to electricity, the Gas Company Climate Planning Framework recommends using the best available information on projected marginal grid mix and emission rates over the analysis time frame. These projected marginal emission rates should account for CLCPA electric sector goals (specifically, that 70 percent of generation statewide will come from renewable sources by 2030, and 100 percent will come from zero-emitting resources by 2040).

Because electrification leads to increased electric sales, additional new demand effectively brings zero-emitting generation onto the grid that would otherwise not have entered the system. Thus, it is reasonable to assume that this zero-emitting component of marginal generation is connected to CLCPA requirements and corresponds with declining marginal rates. If the state meets CLCPA electric sector goals, total marginal GHG emissions from electricity generation in New York would fall from the current rate of approximately 1,010 pounds CO_2e/MWh to zero pounds CO_2e/MWh after 2040.[16]

Figure 6 presents a simplified and illustrative marginal emissions forecast in New York, assuming that zero-emitting resources come online early to meet CLCPA goals. However, it will be necessary to develop a more defined approach to calculating future marginal emissions rates to ensure both electric and natural gas utilities use consistent methodologies in long-term planning activities.

[16] These rates should include all upstream and combustion emissions associated with natural gas, oil, and other fuels used for meeting marginal energy demand.

Figure 6: Projected Marginal Electricity Emissions Rate with CLCPA Electric Sector Goals



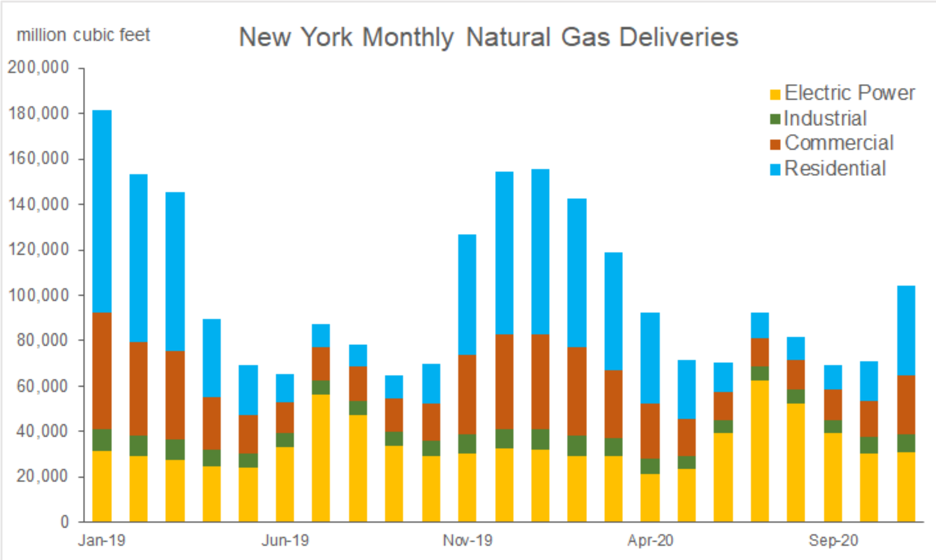
* CLCPA 2040 goal corresponds with zero-emitting resources (including nuclear) while 2030 goal is specific to renewable electricity; defined approach and further analysis necessary to determine marginal emission rates

Source: MJB&A analysis.

Demand Response

Historically, New York natural gas demand is highly variable across the year, with daily demand lowest in June, and highest during the winter heating season, from November to March. See Figure 7 which plots actual monthly demand for 2019-2020. As shown in Figure 7, gas demand peaks in the winter primarily due to heating demand from residential and commercial buildings; peak gas demand for electricity generation is highest in the summer. As the New York grid transitions from natural gas fired generation to renewable sources in response to CLCPA goals, summer gas demand will fall more significantly than winter demand, thus exacerbating the existing winter peak.

Figure 7: 2019-2020 New York Monthly Natural Gas Demand



Source: MJB&A analysis of EIA Monthly Natural Gas Deliveries. See: https://www.eia.gov/naturalgas/monthly/.

The number of customers that an LDC can serve depends on available pipeline capacity and peak day demand. Demand response programs provide an incentive for LDC gas customers to reduce their gas use on peak days. Demand response programs can also reduce the need for peaking supplies CNG and LNG during the coldest days. Demand response programs are intended to reduce costs by increasing utilization factors of existing infrastructure; they are not intended to, nor do they typically reduce annual total gas use.

CNG/LNG Peaking

Like demand response programs, CNG and LNG peaking are intended to allow LDCs to manage and meet winter demand. While demand response programs ameliorate transmission pipeline capacity constraints by reducing peak day demand, CNG and LNG peaking bypass pipeline constraints by locally injecting additional gas into the system, downstream of the city gate, to satisfy peak demand. Prior to injection, this gas is stored at high pressure (CNG) or as a cryogenic liquid (LNG).

For the purposes of this Gas Company Climate Planning Framework, the amount of natural gas from CNG or LNG peaking is the "activity factor" and the same emissions factors applied to other natural gas use should be applied to this gas across all stages of the life cycle. There are additional GHG emissions associated with the CNG/LNG peaking operation itself, and these must also be included in the life cycle GHG emissions analysis. These additional GHG emissions result from energy used to compress natural gas to CNG or to liquefy natural gas to LNG, and to truck the resulting CNG/LNG to the injection point. While CNG is typically compressed, trucked, and injected on the same day, LNG is typically trucked to a local storage location over a period of months before injection. As such, there may be venting/leakage of methane or re-cooling associated with the storage operation which should also be included in the life cycle GHG analysis. Emission factors for production, storage, and transport of CNG and LNG can be developed using GREET.

Conclusion

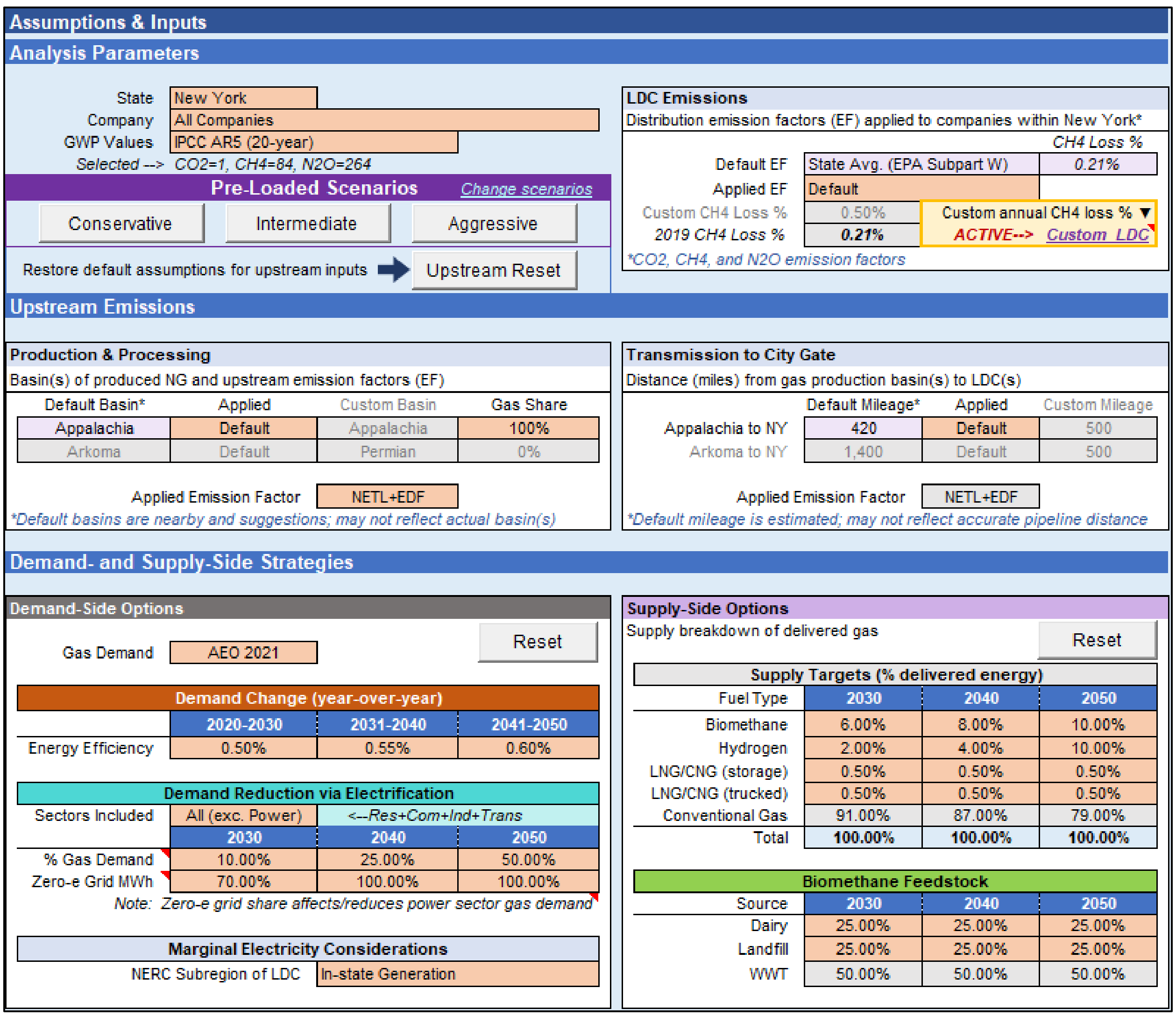
The Gas Company Climate Planning Framework outlined in this report is intended to aide regulators, policymakers, natural gas utilities and stakeholders in integrating and aligning gas planning with climate change laws and policies in a consistent and transparent manner. While the framework addresses quantification of life cycle GHG emissions, there are other important aspects of gas supply planning, such as assessments of LDC and customer costs and system reliability. The methodology described here is intended to be used in conjunction with these other assessments to give a more complete picture of LDC gas supply decision making in the context of state goals to achieve significant reductions of carbon emissions, while assuring New Yorkers have reliable access to affordable energy.

Appendix A: Gas Company Climate Planning Tool

To assist LDCs with use of the Gas Company Climate Planning Framework, MJB&A developed an Excel-based calculation tool—the Gas Company Climate Planning Tool—to help forecast and evaluate various scenarios by incorporating the framework's driving inputs and assumptions and dynamically producing results. LDCs and users can apply custom scenarios to estimate life cycle GHG emissions associated with delivered gas, compare emissions across business-as-usual and user-defined scenarios, and visualize changes in gas demand, emissions, and social costs resulting from the user-defined demand- and supply-side strategies.

Below shows the user interface of the tool and indicates some of the customizable analysis parameters and inputs within each life cycle segment.

Figure A1: Analysis Dashboard (Assumptions & Inputs)



The dashboard also provides results as inputs, assumptions, and strategies are changed. These summary results reflect the annual and cumulative effects of different scenarios on GHG social cost savings, delivered gas and energy demand, and life cycle GHG emissions. Emission changes are evaluated in several different ways, with particular focus on emissions within different life cycle segments and how specific demand- and supply-side strategies impact total emissions. The screenshot below shows the summary charts and tables; more detailed, annual tabular results are also available within the tool.

Figure A2: Analysis Dashboard (Summary of Results)

Representative Example Using Analysis Tool

Using the analytical too, this appendix provides a representative gas planning GHG assessment that includes natural gas supplied by all New York LDCs and applies average statewide distribution GHG emission factors.[17] The assumed source of the conventional natural gas is the Appalachian Basin, with an average transmission distance of approximately 420 miles to New York. Forecasted natural gas demand (~1,350 quads for all LDCs) for all sectors (residential, commercial, industrial, power, and transportation) from Annual Energy Outlook 2021 was used for the business-as-usual supply.

[17] Representative example assumes LDC methane emissions loss rate declines 2% annually through distribution network upgrades (e.g., pipeline replacement, leak repair, etc.)

Supply-Side Strategies

Supply-side strategies include conventional natural gas, biomethane, hydrogen, and LNG and CNG (both stored and trucked). The supply targets as a percentage of total delivered energy in 2030, 2040 and 2050 are provided in Table A1 below.

Table A1: Supply Targets as a Percentage of Delivered Energy

Fuel Type	2030	2040	2050
Biomethane	6%	8%	10%
Hydrogen	2%	4%	10%
LNG/CNG (storage)	0.5%	0.5%	0.5%
LNG/CNG (trucked)	0.5%	0.5%	0.5%
Conventional Gas	91%	87%	79%
Total	100%	100%	100%

The biomethane supply mix was assumed to consist of 25 percent dairy, 25 percent landfill and 50 percent wastewater treatment. The hydrogen supply mix was assumed to consist of 100 percent hydrogen from electrolysis from renewable electricity.

Demand-Side Strategies

Demand-side strategies include energy efficiency, fuel switching to electricity, and reduced natural gas consumption in the power sector to align with the CLCPA goals of 70 percent renewable electricity by 2030 and zero emitting electricity sector by 2040. For illustrative purposes, this scenario assumes that power sector natural gas consumption declines to zero in 2040. Alternative outcomes include continued use of natural gas with carbon capture and utilization or zero carbon gaseous fuel (such as biomethane or hydrogen-based fuels).

The demand-side energy efficiency assumptions include year over year efficiency savings of 0.50 percent per year from 2020-2030, 0.55 percent per year from 2031-2040 and 0.60 percent per year from 2041-2050. Fuel switching assumptions (from gas to electricity) is represented as a reduction of residential and commercial sector gas demand at the following levels: 10 percent by 2030, 25 percent by 2040 and 50 percent by 2050.

Life Cycle GHG Emissions

Business-as-usual (BAU) life cycle GHG emissions are approximately 110.9 million metric tons CO_2e in 2030.[18] When compared to the representative scenario, a 38 percent reduction is projected. Over the long term, the representative scenario is projected to result in a 63 percent reduction below BAU in 2040 and an 80 percent reduction in 2050 (see Table A2 below).

*Table A2: Annual Life Cycle Emissions (MMT CO_2e)**

Year	BAU	Scenario	Change	% Change
2030	110.9	69.2	*-41.7*	**-37.6%**
2040	109.0	40.9	*-68.1*	**-62.5%**
2050	113.7	22.5	*-91.2*	**-80.2%**

* Using IPCC AR5 20-year GWP values

[18] Using IPCC AR5 20-year GWP values

The representative scenario results in more than a 30 percent reduction in conventional natural gas demand compared to BAU by 2030 (including power sector natural gas demand declines in line with 70 percent renewables by 2030). Demand-side energy efficiency and electrification contribute to a greater than 10 percent reduction in natural gas demand compared to BAU by 2030. On the supply side, biomethane and hydrogen contribute to more than a 10 percent reduction in GHG emissions compared to BAU. Table A3 provides the results of the representative scenario in 2030 compared to BAU by demand- and supply-side strategy.

Table A3: Annual Life Cycle GHG Impact in 2030

			% Change (2030 vs. 2020)	
	Strategy	MMTCO2e	NG Demand	Emissions
LDC Upgrades	**Total**	**-0.6**		**-0.6%**
Demand-Side	Efficiency	-3.7	-3.3%	-3.3%
	Electrification	-5.9	-6.7%	-5.4%
	Power Adj.	*-19.3*	*-15.0%*	*-17.4%*
	Total	**-28.9**	**-25.0%**	**-26.1%**
Supply-Side	LNG/CNG	0.0	-0.7%	0.0%
	Hydrogen	-1.6	-1.5%	-1.5%
	Biomethane	-10.5	-4.4%	-9.5%
	Total	**-12.1**	**-6.5%**	**-10.9%**
	Total Change	**-41.7**	**-31.5%**	**-37.6%**

Social Cost of GHGs

The final step in the representative scenario is to calculate the social cost of GHG savings compared to the BAU. Using the Value of Carbon Guidance values of the NY DEC (3 percent discount rate), the representative scenario is estimated to save approximately $2.03 billion (2020$) in 2030. On a cumulative basis from 2021-2030, the representative scenario is estimated to save approximately $10.9 billion (2020$).

To download this tool, view its supplementary user guide, and access other MJB&A tools, please register at www.mjbradley.com/analytical-resources.

Endnotes

[i] Documents pertaining to Case Number 20-G-0131 are available at: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131&submit=Search.

[ii] See: https://www.coned.com/en/save-money/convert-to-natural-gas/westchester-natural-gas-moratorium/about-the-westchester-natural-gas-moratorium.

[iii] Modernized Gas Planning Process: Standards for Reliance on Peaking Services and Moratorium Management, Jointly Filed by New York Utilities, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A66EE1E3-A429-4A0F-9D64-C5D0101BCF42}.

[iv] Gas Regulation for a Decarbonized New York Recommendations for Updating New York Gas Utility Regulation, Synapse Energy Economics, prepared on behalf of NRDC, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1D31BC7D-E315-4F77-8AEF-23AC5E998755}.

[v] Zero Net Gas: A Framework for Managing Gas Demand Reduction as a Pathway to Decarbonizing the Buildings Sector, Pace Energy and Climate Center, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={36D3AA36-EACB-40B1-9A67-EBD2CE6BE8E7}.

[vi] New York State Department of Public Service, Staff Gas System Planning Proposal, Case Number 20-G-0131 on February 12, 2021, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={89D286C6-CAB7-4D3B-8BE9-4B73ED09BECE}

[vii] National Fuel filing to Case Number 20-G-0131 on September 17, 2020, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131&submit=Search.

[viii] Con Edison filing to Case Number 20-G-0131 on August 17, 2020, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131&submit=Search.

[ix] For more information, see https://www.epri.com/lcri.

[x] National Fuel filing to Case Number 20-G-0131 on August 17, 2020, available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=20-g-0131&submit=Search.

[xi] NYS Clean Heat - Statewide Heat Pump Program information is available at https://www.nyserda.ny.gov/All-Programs/Programs/NYS-Clean-Heat

[xii] Ocko et al., 2017, https://wws.princeton.edu/system/files/research/documents/Science%20356.%20pg492.full_.pdf.

[xiii] The DEC Guidance is available at https://www.dec.ny.gov/docs/administration_pdf/vocfguid.pdf and DEC's social cost values are available at https://www.dec.ny.gov/docs/administration_pdf/vocfapp.pdf. DEC developed the Guidance in consultation with the New York State Energy Research and Development Authority (NYSERDA) and Resources for the Future (RFF). Relatedly, RFF and NYSERDA released a memo in October 2020 in support of DEC's issuance of the Draft Guidance. See: "Estimating the Value of Carbon: Two Approaches," RFF and NYSERDA, available at https://www.dec.ny.gov/docs/administration_pdf/vocmemo.pdf.

[xiv] Life Cycle Analysis of Natural Gas Extraction and Power Generation, National Energy Technology Laboratory, https://www.netl.doe.gov/LCA.

[xv] New York State Oil and Gas Sector Methane Emissions Inventory, July 2019, https://www.nyserda.ny.gov/-/media/Files/EDPPP/Energy-Prices/Energy-Statistics/NYS-oil-and-gas-sector-methane-emissions-inventory.pdf.

[xvi] NYS DEC, Part 496, Statewide GHG Emissions Limits, https://www.dec.ny.gov/regulations/121052.html.

[xvii] EPA's Greenhouse Gas Reporting Program (GHGRP), subpart W, https://www.epa.gov/ghgreporting/subpart-w-reported-data.
[xviii] EPA's Emission Factors for GHG Inventories, https://www.epa.gov/sites/production/files/2020-04/documents/ghg-emission-factors-hub.pdf.
[xix] NY DEC, 6 NYCRR Part 496 Statewide Greenhouse Gas Emission Limits, https://www.dec.ny.gov/docs/administration_pdf/revexpterms496.pdf.
[xx] UN IPCC, AR 5, Chapter 8: Anthropogenic and Natural Radiative Forcing, https://www.ipcc.ch/site/assets/uploads/2018/02/WG1AR5_Chapter08_FINAL.pdf.
[xxi] Lamb, Brian K. et al. "Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States," *Environmental Science & Technology*, March 31, 2015. Available at: https://pubs.acs.org/doi/10.1021/es505116p.
[xxii] Weller, Zachary D., Hamburg, Steven P., and von Fischer, Joseph P. "A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems," *Environmental Science & Technology*, June 10, 2020. Available at: https://pubs.acs.org/doi/abs/10.1021/acs.est.0c00437.
[xxiii] Argonne National Laboratory, GREET model, https://greet.es.anl.gov/.
[xxiv] CARB, LCFS pathway certified carbon intensities, https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities.
[xxv] CARB pathway calculators are available at: https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation.
[xxvi] Argonne National Laboratory, GREET model, https://greet.es.anl.gov.
[xxvii] CARB pathway calculators are available at: https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation.
[xxviii] Paulot et al., 2021, https://www.sciencedirect.com/science/article/abs/pii/S0360319921001804?via%3Dihub. Also see: Derwent et al., Global Environmental Impacts of the Hydrogen Economy, January 2006, https://www.geos.ed.ac.uk/~dstevens/Presentations/Papers/derwent_ijhr06.pdf.
[xxix] *See*: Bond et al., 2011, https://www.sciencedirect.com/science/article/abs/pii/S036031991002063X; Ruijven et al,, 2011, https://www.sciencedirect.com/science/article/abs/pii/S0959378011000409.
[xxx] NYSERDA, New Efficiency: New York, Analysis of Residential Heat Pump Potential and Economics, January 2019. https://www.nyserda.ny.gov/-/media/Files/Publications/PPSER/NYSERDA/18-44-HeatPump.pdf.
[xxxi] NYISO, 2020 Power Trends Report, https://www.nyiso.com/documents/20142/2223020/2020-Power-Trends-Report.pdf/dd91ce25-11fe-a14f-52c8-f1a9bd9085c2.
[xxxii] NYS PSC, CASE 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework, January 21, 2016.
[xxxiii] EPA Emissions & Generation Resource Integrated Database (eGRID), 2019, https://www.epa.gov/egrid.
[xxxiv] Per the Clean Energy Advisory Council (CEAC) Metrics, Tracking, and Performance Assessment (MTPA), applicable for all Regional Greenhouse Gas Initiative (RGGI)-funded projects (energy efficiency, renewable electricity installations, etc.) completed after 2015; projects completed prior to 2016 assume a marginal rate of 1,160 pounds CO_2e/MWh based on analysis of grid emissions at the time.
[xxxv] EPA, Emissions & Generation Resource Integrated Database (eGRID), 2019, https://www.epa.gov/egrid.