Supplemental Greenhouse Gas Analysis of the Danskammer Energy Center

July 8, 2020

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Table of Contents

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1 EXECUTIVE SUMMARY

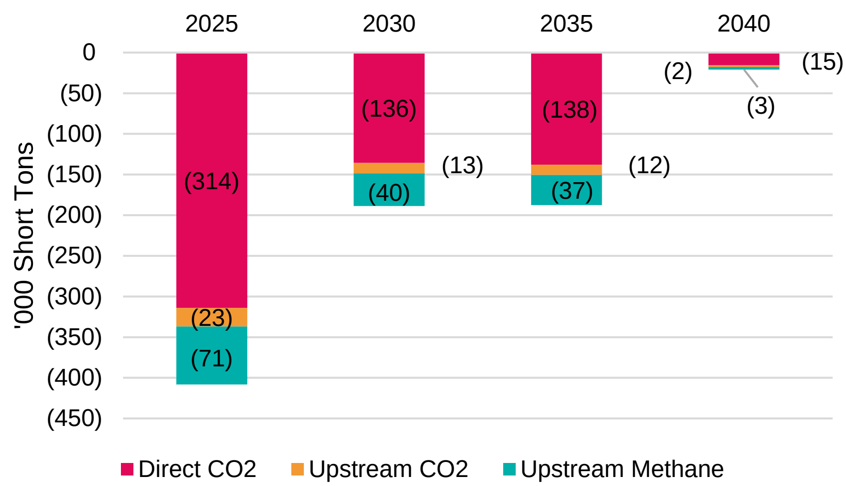
ICF was engaged by Danskammer Energy, LLC (Danskammer) to prepare this report in connection with (i) its Article 10 application to the Board of Electric Generation Siting and the Environment (the Siting Board), and (ii) its application to modify its Title V operating permit submitted to the New York State Department of Environmental Conservation (NYSDEC), for the proposed Danskammer Energy Center (the Project). Chapter 1 of this report establishes how the Project is consistent with New York State's (NYS) greenhouse gas (GHG) reduction requirements and contributes to the achievement of Climate Leadership and Community Protection Act (CLCPA) electric system targets. This report also provides a summary of the scope of work, modeling tools, and major assumptions used; explains ICF's methodology for developing a CLCPA-consistent resource mix in 2040; and presents its modeling results.

The key findings of this report, which are described in full detail in Section 2.3, are:

- Since the Project would be among the most efficient electric generating facilities in NYS, it will reduce system-wide GHG emissions in the northeast[1] by displacing less efficient and higher-emitting generating facilities both inside and outside NYS.
- As demonstrated in the chart below, due to the Project's high efficiency and state-of-the-art emissions controls, overall fuel consumption and associated GHG emissions fall annually on an average by 196,000 tons and 261,000 tons after accounting for upstream emissions between 2025 and 2035. In 2040 and beyond, while GHG emissions in NYS from the electric sector are assumed to be zero, the Project causes emissions outside NYS to be reduced by 20,000 tons annually.

[1] Northeast region for the purposes of this study encompasses NYISO, ISO-NE, PJM and Ontario. Due to the interconnected nature of the northeastern power system, the Project displaces less-efficient generators both inside and outside NYS. Thus, it is more appropriate to consider the broader northeast region for any impact analysis studies.

Figure 1-1: GHG Impacts of the Project in the Northeast



- The Project would be complementary to intermittent renewable energy resources added to the NYS electric grid by providing a flexible resource to the electric system due to its quick ramp rate.
- The most cost-effective solution to meet the 2040 CLCPA target is to build large amounts of new offshore wind, solar and battery storage capacity, and retain some thermal resources, such as the Project, and convert them to renewable natural gas (RNG) or hydrogen.
- According to a study for the New York State Energy Research and Development Authority (NYSERDA)[2], higher electrification in NYS, which is anticipated to be necessary to meet CLCPA GHG reduction requirements, would significantly increase electricity demand and may lead to challenges in meeting demand reliably. Periods of low renewable generation availability could place added stress on the system without the availability of fast-start thermal RNG-capable resources such as the Danskammer Energy Center.

2 INTRODUCTION

2.1 Background

Danskammer is proposing to repower and replace the existing Danskammer generating station with the Danskammer Energy Center, a new state-of-the art, efficient natural gas-fired combined cycle generating unit (the Project). In support of the Project, on December 11, 2019, Danskammer submitted an Application to the Siting Board for a Certificate of Environmental Compatibility and Public Need under Article 10 of the Public Service Law. On November 15,

[2] Energy+Environmental Economics, New York State Decarbonization Pathways Analysis, June 24, 2020

2019, in anticipation of the Article 10 Application, Danskammer also submitted an application to NYSDEC to modify its Clean Air Act Title V operating permit.

In June 2019, NYS passed the CLCPA, which became effective on January 1, 2020. Among other things, the CLCPA adds a new Article 75 to the Environmental Conservation Law (ECL). The new ECL Section 75-0107 requires NYSDEC to promulgate regulations that reduce Statewide GHG Emissions to 60% of 1990 levels by 2030 and to 15% of 1990 levels by 2050. In the new ECL Section 75-0105, the CLCPA also requires NYSDEC to issue a report on Statewide GHG Emissions, including, among other things, an estimate of what the statewide GHG emissions level was in 1990.

Although these regulations and report have not yet been developed by NYSDEC, Section 7(2) of the CLCPA requires all state agencies to consider whether the decision to issue permit(s) is inconsistent with or will interfere with the attainment of the GHG emission estimated limits established pursuant to ECL Article 75. In a separate provision, moreover, the CLCPA amends the Public Service Law to require the New York State Public Service Commission (PSC) to implement a program to achieve the following targets: 70% of statewide electric generation from renewable energy systems by 2030; zero emissions from the statewide electric system by 2040.

Exhibit 10 of Danskammer's Article 10 Application, titled Consistency with Energy Planning Objectives, concluded that the Project would be consistent with the (then-effective) 2015 State Energy Plan (SEP) as well as the CLCPA. Because the repowered facility will be among the most efficient thermal generators in NYS, it will reduce system-wide GHG emissions by displacing less efficient and higher-emitting generating facilities. Further, the Project will provide flexible, load-following capabilities due to its quick ramp rate of [redacted] MW per minute (within 8 hours of last shutdown). Thus, it will be complementary, not detrimental to, the addition of intermittent renewable sources in NYS.

In an attachment to a deficiency letter issued by the Siting Board on February 10, 2020, NYSDEC stated that both the Danskammer Article 10 application and the Title V application were deficient because they did not include the following:

- An assessment of how the issuance of a Title V permit modification by the DEC would be consistent with the greenhouse gas emissions limits established in Article 75 of the environmental conservation law, as required by Section 7(2) of the Climate Leadership and Community Protection Act (Chapter 106 of the Laws of 2019).
- An assessment of how the Siting Board's issuance of an Article 10 Certificate for the Project would be consistent with the Statewide greenhouse gas emission limits established in Article 75 of the environmental conservation law, as required by Section 7(2) of the Climate Leadership and Community Protection Act (Chapter 106 of the Laws of 2019).[3]

[3] The NYSDEC also separately issued a Notice of Incomplete Application (NOIA) with respect to the application for a modification to the Title V permit application, which listed an identical deficiency with respect to the CLCPA.

This report, therefore, provides the supplemental analysis in response to the identified deficiencies, and assesses the impact of the Project on GHG emissions.

2.2 Scope of Work and Modeling Approach

ICF's analysis addresses two key questions regarding the Project's consistency with the CLCPA:

- To what extent is the Project consistent with CLCPA GHG reduction requirements, and
- Does the Project help NYS achieve its long-term energy targets of a zero-emissions statewide electric system by 2040?

To evaluate the Project's consistency with the CLCPA, ICF first developed a forward-looking resource mix for NYS using its proprietary Integrated Planning Model (IPM). This resource mix was optimized to meet all clean energy and zero-emissions targets while meeting reserve margin requirements. The optimization also accounted for transmission capabilities, capital costs and other assumptions (see Section 3). After determining the most economic resource mix, ICF followed the typical approach to assessing the impacts of a proposed facility on the electricity system, which is to first model the system without the facility (the Base Case), and then to model it with the facility (the Change Case). ICF used ABB's PROMOD production cost modeling software to assess the impacts of the Project based on the resource mix determined using IPM. This methodology is similar to that employed in Exhibit 8 of Danskammer's Article 10 application, except that it has been extended out to 2040. The Project's impact was estimated for the 2025-2040 forecast period, with 2025, 2030, 2035 and 2040 being the model run years.

It is important to emphasize that this analysis does not address all avenues of consistency with the CLCPA. Specifically, the Project could retire if declining renewable and battery storage costs compel it to. This is a risk that will be borne by the developers of the Project since it is being built without any financial assistance from NYS or its ratepayers. In fact, consistent with the conclusions set forth in Exhibit 8, to the extent the Project displaces less efficient thermal generation through 2040, it will reduce costs to ratepayers. Additionally, the Project could be required by NYS to continue to operate using natural gas in 2040 in order to meet NERC and other reliability requirements.4 This analysis does not address this scenario due largely to the extreme complexity involved and uncertainty regarding future conditions.

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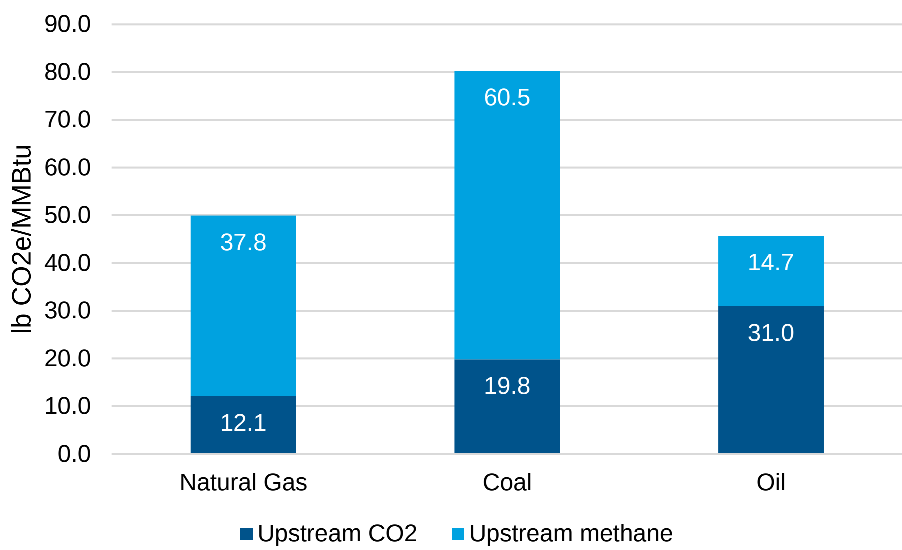
[4] The CLCPA added a new Section 66-p to the Public Service Law entitled Establishment of a Renewable Energy Program, which, among other things, specifically provides in subsection (2): "In establishing such program, the [Public Service Commission] shall consider and where applicable formulate the program to address impacts of the program on safe and adequate electric service in the state under reasonably foreseeable conditions. The [Public Service Commission] may, in designing the program, modify the obligations of jurisdictional load serving entities and/or the targets upon consideration of the factors described in this subdivision." Further, in Section 66-p(4) further states that the Public Service Commission "may temporarily suspend or modify the obligations under such program provided that the commission, after conducting a hearing as provided in section twenty of this chapter, makes a finding that the program impedes the provision of safe and adequate electric service; the program is likely to impair existing obligations and agreements; and/or that there is a significant increase in arrears or service disconnections that the commission determines is related to the program."

ICF calculated the impact on both direct and indirect (upstream) GHG emissions associated with the operation of the Project. Direct GHG emissions impacts were obtained from PROMOD, while upstream emission impacts were calculated using national and regional emissions factors, associated with the change in fuel consumption for electric generation both within NYS and the overall northeast region. For all fossil fuels, there are upstream emissions due to energy used in processing and transportation of the fuel, venting of CO2 and methane, and leakage. As explained later in the report, ICF used national-level upstream emission factors since these are higher than those in the northeast, and hence, yielded more conservative results (see Appendix A-5). Figure 2-1 presents ICF's estimated upstream emissions for natural gas, coal and oil in the northeast region.[5]

Figure 2-1: Northeast Region Upstream Emission Rates for Natural Gas, Coal and Oil



ICF developed cost and volume estimates for two zero-emissions fuels, RNG and hydrogen, to inform its analysis of the Project's consistency with the CLCPA electric system targets. To estimate RNG potential for NYS in 2040, ICF drew upon a previous assessment of RNG potential it had developed for the American Gas Foundation (AGF).[6] The estimate was based on an inventory of RNG feedstocks and production volumes accessible to NYS. ICF then developed cost estimates for RNG production from various feedstocks such as landfill gas, municipal solid waste, animal manure, food waste, etc. The cost estimates were further refined by region to arrive at a cost versus availability estimate. Figure 2-2 presents the RNG cost curve used in this study. ICF's detailed methodology to develop the cost curve is provided in Appendix A-3.

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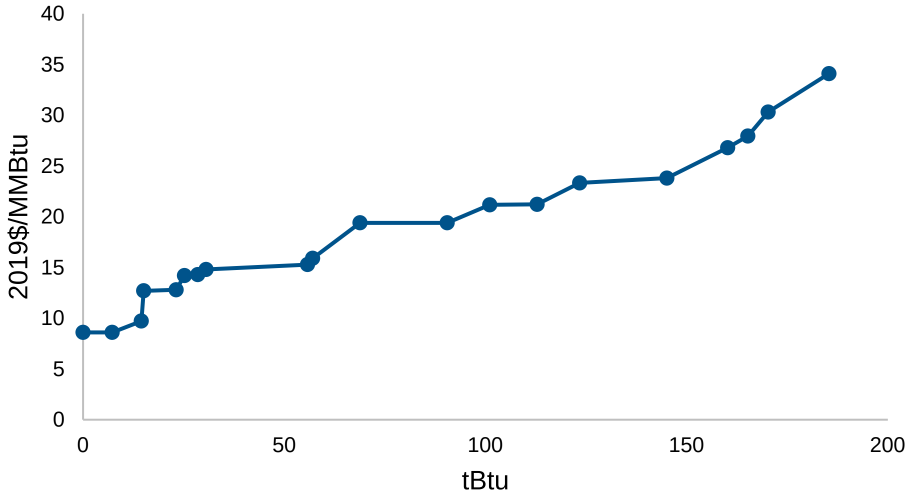
[5] Upstream emissions of methane are estimated using a Global Warming Potential (GWP) of 86, reflecting methane's 20-year GWP.

[6] ICF, Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment, December 2019. Source: https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

Figure 2-2: RNG Cost Curve in 2040



2.3 Key Findings

Reduction in GHG emissions: Throughout the forecast period, the operation of the Project leads to a reduction in both the direct and upstream GHG emissions in the northeast region[7]. Due to the interconnected nature of the northeastern power grid, operation of the Project displaces other less efficient generators in the northeast both inside and outside NYS. As a result, overall fuel consumption, and thus, associated GHG emissions, fall. In 2025-2035, direct GHG emissions fall by an average of 196,000 short tons per year. After accounting for upstream emissions, the average GHG reduction rises to 261,000 tons per year. In 2040, when NYS transitions to a zero-emissions electric system, the Project continues to lead to a reduction in both direct and upstream GHG emissions by displacing conventional fossil-fuel generation outside NYS. The analysis finds that in 2040, the Project leads to an annual reduction in GHG emissions of 20,000 tons in the northeast region. Figure 2-3 presents the GHG impacts of the Project in the northeast region.

[7] For this analysis, the "northeast region" comprises NYISO, ISO-NE, PJM, and Ontario.

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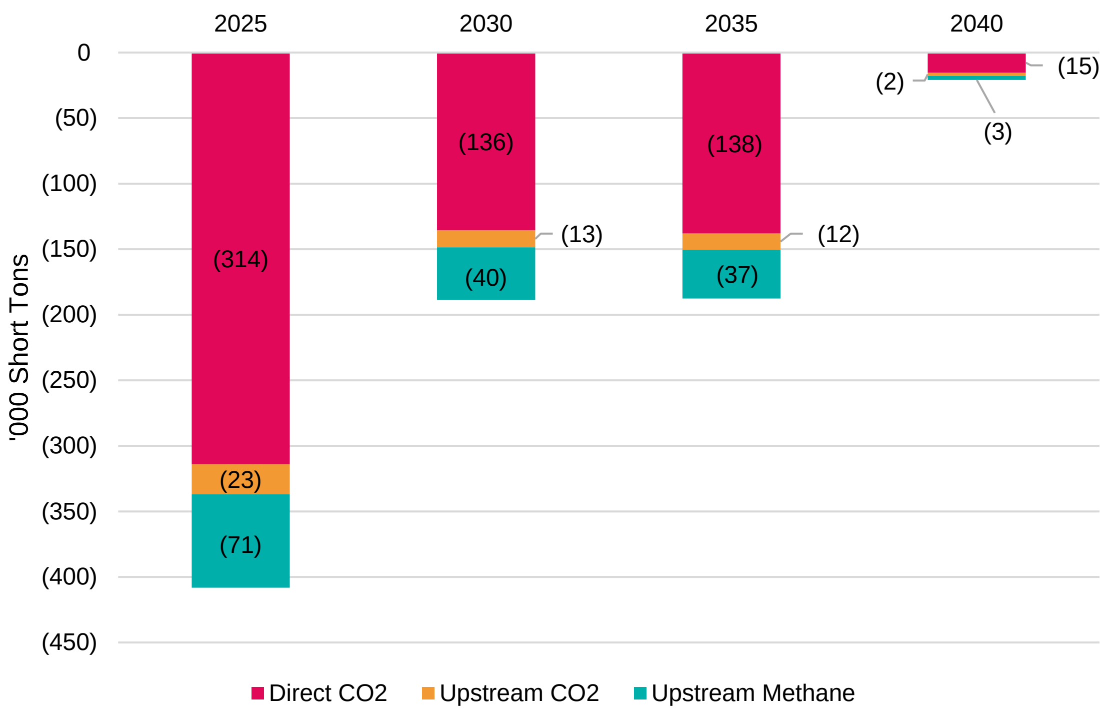
Figure 2-3: GHG Impacts of the Project in Northeast



Efficient, RNG-capable thermal resources such as the Project play an important role in NYS's future generation mix: ICF's analysis finds that the most cost-effective solution for a future resource mix that is consistent with the CLCPA targets involves retaining some existing thermal resources converted to RNG combined with new renewable and energy storage resources. Figure 2-4 and Figure 2-5 show NYS's capacity and generation mix (including the Project) in 2040.

Figure 2-4: CLCPA-Consistent Capacity Mix (in GW) in 2040 in NYS

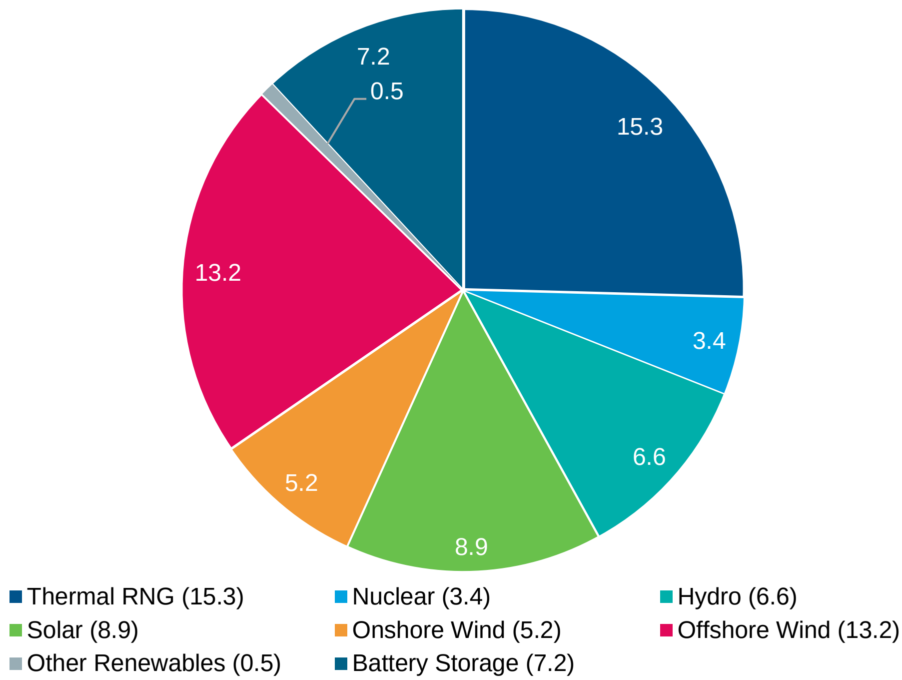
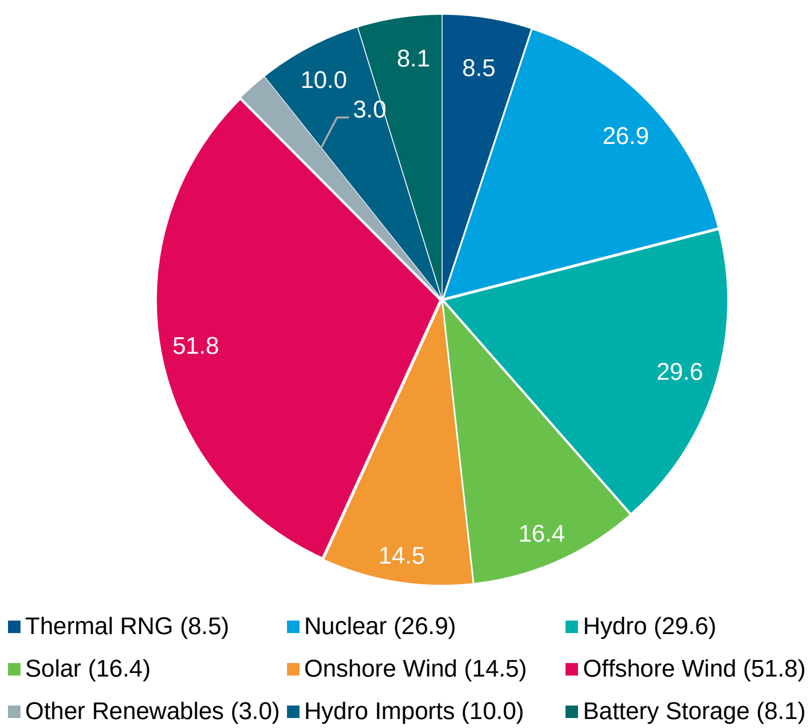


Figure 2-5: CLCPA-Consistent Generation Mix (in TWh) in 2040 in NYS



The least-cost resource mix is driven by two primary requirements – to maintain adequate reserve margin, and to meet the CLCPA targets of 70% renewable energy by 2030 and a 100%

zero-emission electric system by 2040. Due to the rapidly falling capital costs and minimal variable costs of renewable resources, ICF finds it optimal to utilize these resources to meet the CLCPA targets. Thus, renewable and battery storage resources make up most of the generation capacity. However, since renewable resources do not provide much reserve margin contribution (solar PV only provides 2% in the winter), it is more cost effective to retain some thermal resources to meet resource adequacy requirements. Thus, in 2040, ICF's projected capacity resource mix comprises 15 GW of thermal RNG resources, 13 GW of offshore wind, 5.2 GW of onshore wind, 8.9 GW of utility-scale solar PV, and 7.2 GW of 4 and 8-hour battery storage. The thermal capacity retained in 2040 comprises the most efficient and flexible combined cycle gas turbines (CCGT) and combustion turbines (CT). These resources play an important role as capacity and load-following resources to help meet reserve margin and reliability requirements. Given the relatively high costs of RNG (see Appendix A-3), the average capacity factor of thermal RNG generators in 2040 is only about 6%, and they provide only 5% of the state's zero-emissions electricity.

The Project is a prime candidate to be retained in 2040: By 2040, as renewable resources become dominant, the need for flexible, on-demand dispatchable capacity rises in order to supplement the intermittent nature of renewable generation. Resources such as the Project, with quick start-up and ramp times, provide key "load-following" services to tide over any shortfalls in renewable generation due to resource unavailability. The Project is proposed to be one of the most efficient and flexible CCGTs in NYS, with the potential to produce energy from both RNG and hydrogen. It has a ramp rate of up to [redacted] MW/min[8] and can reach its full 600 MW output in less than an [redacted] In comparison, the current Danskammer steam turbines (ST) have a ramp rate of [redacted] MW/hour and require [redacted] hours of lead time before starting up. Due to its flexibility, the Project generates at a capacity factor of [redacted] in 2040, which is higher than the 6% average of all thermal RNG resources. Thus, the Project is one of the best thermal resources in NYS to retain.

Adequate RNG supplies: ICF's analysis indicates that the supplies of RNG available to NYS are sufficient for the amount of thermal RNG generation estimated for 2040 and beyond. In 2040, total RNG consumption is 70 tBtu, which is much less than the 185 tBtu estimated to be available readily in NYS. As explained later in the report, ICF notes that for this analysis, avoided methane emissions from RNG use were set at a zero emission rate (see Appendix A-5).

Hydrogen acts as a backstop and interacts with renewable output: The quantity of available hydrogen is infinite (as long as water is available), but its cost is a function of the cost of power. At current estimates, the cost of hydrogen in 2040 is $45/MMBtu (in nominal terms) for up to 30 tBtu of fuel. However, the greater the reliance on renewables, the lower the hydrogen price to the extent excess renewable production is used to produce hydrogen.

[8] While it is running, or has been shut down no more than [redacted] hours prior to ramping up.

2.4 Consistency with other long-term studies in New York and California

ICF's findings are consistent with recent deep decarbonization studies for New York and California. These studies have shown that some level of thermal generation in the form of advanced quick-start, dispatchable combined cycle plants like the Project will likely be required in power systems pursuing deep decarbonization. A study conducted for New York State Energy Research and Development Authority (NYSERDA)[9] found that in a high electrification scenario, meeting heating loads during winter months would be challenging due to low renewable energy production, which can stretch over several days. The study concluded that this long-duration reliability challenge can be solved through a combination of large-scale hydro, RNG, hydrogen, carbon capture and storage (CCS), and nuclear power.[10] Separately, the NYISO commissioned the Brattle Group to simulate resources that can meet state policy objectives and energy needs through 2040.[11] The study similarly concluded that dispatchable zero-emission sources such as RNG-fired thermal units would grow in capacity in order to meet the 2040 zero-emission energy and resource adequacy needs.[12] In the Brattle Group report, the generation from these plants decreases but capacity needed increases, showing a falling capacity factor.[13]

Studies for California have yielded similar conclusions. A study sponsored by the California Energy Commission (CEC) concluded that "by 2050, 85% to 95% zero-carbon electricity is expected to be required; however, 100% zero-carbon electricity is likely to be cost prohibitive compared to alternative GHG mitigation strategies."[14] In a California Public Utilities Commission (CPUC) November 2019 study,[15] the CPUC forecasts for 2045 concluded:

- "Almost all gas fired capacity retained past 2030 due to high peak demand" under all 2045 scenarios examined[16]
- "Gas capacity necessary to maintain reliability, even with significant buildout of out of state transmission or offshore wind"[17]
- "Electricity sector generation will result in CO_2 emissions in all scenarios"[18]

California also expects to rely on biofuels and hydrogen to provide additional options for continued gas powerplant role. For example, in the CPUC study, the Commission identifies three 2045 decarbonization scenarios – high electrification, high biofuels and high hydrogen. The high biofuels and high hydrogen scenarios focus on alternative types of gaseous fuels whose

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[9] Energy+Environmental Economics, New York State Decarbonization Pathways Analysis, June 24, 2020
[10] Ibid, pg. 21
[11] New York's Evolution to a Zero Emission Power System, Modeling Operations and Investment Through 2040, May 18, 2020, prepared for New York Stakeholders, Prepared by the Brattle Group.
[12] Ibid. pg. 22
[13] Ibid, pg. 23
[14] California Energy Commission, Deep Decarbonization in a High Renewables Future, June 2018
[15] California Public Utilities Commission (CPUC), 2019-2020 Proposed Reference System Plan, CPUC Energy Division, November 6, 2019
[16] Ibid, Page 158
[17] Ibid, Page 161
[18] Ibid, Page 152,

combustion would not increase CO_2 emissions.[19] Gas power plants can use these fuels, creating the option to extend the reliance on existing gas power plants. The CPUC study concludes that almost all existing gas power plants will be retained in these cases.[20]

In both the case of California and New York, the growing reliance on electrification will increase the importance of reliability and resiliency because energy delivery will increasingly rely on one delivery system, power, rather than multiple systems such as natural gas, power and oil. Therefore, there will be an even greater need for flexible thermal generation. For example, similar to the conclusion of the NYSERDA study, the CPUC study finds that higher electrification increases electricity demand and leads to challenges in meeting demand reliably.[21] As such, if electricity demand is high in winter months in California, periods of low solar generation could place added stress on the system, and further diminish the likelihood that California will eschew the critical reliability contribution of its existing gas fleet.

3 MODELING TOOLS AND ASSUMPTIONS

3.1 Modeling Tools

ICF's proprietary modeling tool, IPM, was used to analyze the power sector outlook. IPM was developed by ICF to be the primary modeling tool for the US Environmental Protection Agency to analyze the impact of emission regulations on the power and fuel industries at national and regional levels. ICF has utilized IPM for a variety of clients such as Regional Greenhouse Gas Initiative (RGGI), NYSERDA, and utilities to assess the impacts of alternative policy and market assumptions on New York CO_2 emissions and its power markets.

ICF used ABB PROMOD IV, an industry-standard and DPS-approved software, for production cost modeling. PROMOD considers generating unit characteristics, forced outages, transmission topology and constraints, and market system operations to simulate security-constrained economic dispatch of generating units.

To estimate the upstream GHG emissions, ICF relied primarily on EPA, DOE and EIA sources. The analysis was based on the expected sourcing of natural gas, and the information about emissions from these sources. ICF calculated the greenhouse gas emissions in CO_2e using 20 and 100-year GWP. To calculate the regional emissions factors, ICF used its proprietary methane emissions estimator developed in 2019. The estimator differentiates methane emissions by producing basin as well as segment (production, gathering, processing, transmission, and distribution).

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[19] Ibid, page 150. Combustion of hydrogen produced via electrolysis using renewable power during excess generation periods results in emission of water. Biofuels such as renewable natural gas is sourced in a manner which prevents the release of methane into the atmosphere.
[20] Ibid, page 158.
[21] Ibid, pages 150 -165

3.2 Modeling Assumptions

Table 3-1 below summarizes ICF's modeling assumptions for this analysis.

Table 3-1: Summary of Modeling Assumptions

Parameter	Modeling Assumption
Modeling Years	2025, 2030, 2035, 2040
Environmental Regulations	Full CLCPA Compliance
Peak Load Forecast	2020 NYISO Gold Book Baseline Forecast adjusted for high BTM Solar and high energy efficiency from Low Load Scenario
Energy Use Forecast	2020 NYISO Gold Book Baseline Forecast adjusted for high BTM Solar and high energy efficiency from Low Load Scenario
DERs and Energy Storage	2020 NYISO Gold Book Baseline Forecast of Energy Storage; High BTM Solar from Low Load Scenario
Energy Efficiency	High Energy Efficiency from 2020 NYISO Gold Book Low Load Scenario
Firm Builds	Updated as per 2020 Gold Book, and 2018 CARIS Phase 2 Base Case Assumptions and Preliminary Results. Includes CPV Valley, Cricket Valley, Copenhagen Wind, Arkwright Summit, Cassadaga Wind, Baron Wind, 8 Point Wind, Number 3 Wind, and Bluestone Wind
Firm Retirements	Updated as per 2020 Gold Book, and 2018 CARIS Phase 2 Base Case Assumptions and Preliminary Results. Includes Indian Point units 2 and 3. Also includes Cayuga and Somerset.
Renewable Build Costs	Costs based on NREL 2019 ATB with EPA regionalization factors for NY
Thermal Build Costs (excluding CCGT with CCS)	NREL 2019 ATB with EPA regionalization factors for NY
CCGT with CCS Capital Cost	EPA v6
RNG and Hydrogen Fuel Availability and Price Forecast	Based on several feedstocks (landfill gas, animal manure, etc.) from the eastern seaboard, weighted by New York's share of natural gas consumption
Natural Gas Fuel Price Forecast	

Parameter	Modeling Assumption
	2018 CARIS Phase 2 fuel forecasts, applied on a monthly basis
Emissions Price Forecast	Updated as per 2018 CARIS Phase 2 Base Case Assumptions and Preliminary Results

ICF used a combination of the Baseline Forecast and the Low Load Forecast from the NYISO's 2020 Gold Book to model a conservative demand scenario. This scenario uses the Baseline Forecast modified to include high energy efficiency and high BTM solar PV from the low load forecast (Table 3-1). Thus, the peak and energy demand used are lower than the Gold Book's baseline forecast. This is a very conservative scenario since it does not assume completion of many of the other economy-wide CLCPA targets such as electrification of space heating and transportation. Appendix A-1 contains detailed peak and energy assumptions.

ICF's capital cost assumptions for renewable energy and storage technologies were derived from the 2019 NREL Annual Technology Baseline (ATB). Assumptions for non-renewable technologies were sourced from EPA's Power Sector Modeling Platform v6 and EIA's Annual Energy Outlook (AEO 2019). Additionally, the capital costs were scaled according to region based on EPA's cost regionalization factors from its Power Sector Modeling Platform v6. Detailed capital cost assumptions are provided in Appendix A-2.

Table 3-2 below shows the Project's plant parameters.

Table 3-2: Proposed Danskammer Energy Center Plant Parameters

Parameter	Modeling Assumption
Fuel Type	Natural Gas/RNG/Hydrogen (with minor modifications)
Prime Mover	Combined Cycle Gas Turbine
Primary Gas Hub	Central Hudson Gas & Electric, which receives gas from Iroquois Z2, Algonquin, Tetco M3, TGP Z5 and TGP Z6
Proposed Online Year	2023
Summer DMNC[22] UCAP (MW)	600
Winter DMNC UCAP (MW)	600
Base Block Full Load Average Output (MW)	[redacted]
Duct Block Average Incremental Output (MW)	[redacted]
Annual Average Full Load Base Heat Rate (Btu/kWh)	[redacted]
Annual Average Base + Duct Heat Rate (Btu/kWh)	[redacted]

[22] Dependable Maximum Net Capability

Parameter	Modeling Assumption
Variable O&M Costs at Full Load ($/MWh)	[redacted]
Emissions	
CO_2 (lbs/MMBtu)	[redacted]

4 MODELING RESULTS

This section presents and discusses the results of ICF's analysis of the Base Case and Change Case for four discrete run years – 2025, 2030, 2035 and 2040. The first sub-section discusses New York's resource and generation mix as the CLCPA requirements and targets are implemented, and the subsequent sub-section discusses the impact of the Project on direct and upstream greenhouse gas emissions in NYS.

4.1 CLCPA Consistent Resource Mix

ICF's assessment of New York's future resource mix was driven by the need to maintain adequate reserve margin in the NYISO electric system and meet the CLCPA's electricity supply targets at the same time. Thus, the optimal solution incorporates a mix of capacity resources required to maintain reliability, and energy resources required to fulfill the CLCPA targets. The most cost-effective resource mix relies on new offshore wind, onshore wind and solar PV capacity to produce non-emitting generation sufficient to meet the 70x30 and the 100x40 targets, and that also relies on existing thermal capacity reconfigured to burn RNG and new energy storage for reserve margin requirements. Thus, flexible, efficient, and biofuel-capable thermal resources such as the proposed Danskammer Energy Center play an important role in the projected resource mix to provide key load-following and reliability services.

Table 4-1 presents ICF's projected resource mix with Danskammer online for 2025, 2030, 2035 and 2040. Between 2025 and 2035, a significant increase in offshore wind, solar PV and battery storage is expected to meet the resource-specific requirements of the CLCPA.

Table 4-1: Projected Resource Mix (in MW) in the Change Case

Capacity Type	2025	2030	2035	2040
Thermal	24,944	20,413	19,635	15,347
Nuclear	3,361	3,361	3,361	3,361
Hydro	6,624	6,624	6,624	6,624
Solar	4,261	4,261	8,298	8,935
Onshore Wind	5,220	5,220	5,220	5,220
Offshore Wind	1,696	6,098	9,000	13,197

Capacity Type	2025	2030	2035	2040
Other Renewables	481	481	481	481
Battery Storage	1,500	3,000	3,000	7,184

Between 2025 and 2035, ICF projects the renewable capacity to increase to 9 GW of offshore wind, 5.2 GW of onshore wind, 8.3 GW of solar PV and 3 GW of battery storage in NYS. Prior to 2040, the renewable additions are driven by New York State mandates such as the 9 GW offshore wind target by 2035 as well as the 3 GW energy storage requirement by 2030. In addition, the requirement to meet 70% of the energy demand from renewable sources in 2030 drives incremental renewable builds in 2030.

In 2040, as NYS transitions to a 100% zero-emission electricity system, additional offshore wind and solar capacity is added to supply non-emitting generation, with offshore wind reaching over 13 GW and solar almost 9 GW of installed capacity. An incremental 4.2 GW of battery storage is also projected beyond the firmly planned 3 GW, reaching a total installed capacity of 7.2 GW. The incremental storage capacity is added as thermal units, especially old, large and inflexible oil/gas steam units, are projected to retire. These retirements prior to 2040 are balanced through additions of offshore wind capacity in particular, and, as additional thermal facilities retire in 2040, 8-hour battery storage. While thermal generating capacity is projected to retire prior to 2040, substantial amounts of capacity are also projected to retrofit to burn RNG, maintaining over 15 GW of capacity in the system in 2040.

The need to retain existing natural gas capacity by converting it to burn RNG in 2040 is three-fold. First, there is a need for overall capacity levels (or resource adequacy) that can be reliably committed to satisfy demand at any time, including in periods of low renewable generation. According to the NYISO, "as intermittent resources like wind and solar expand across the bulk power system, the Installed Reserve Margin (IRM) percentage will increase because intermittent resources do not contribute an equivalent amount of capacity to reliably meet peak demand as dispatchable resources. Policymakers will need to be cognizant that the intermittency of renewable resources requires that flexible and controllable capacity be available to meet load in the absence of sufficient energy production."[23] Further, it is noted that since individual wind and solar may be simultaneously affected by regional wind conditions, such as extended periods of low wind, maintaining resource adequacy would pose a challenge in the absence of dispatchable generation.[24] Indeed, a study prepared for the NYISO stakeholders[25] found that the marginal capacity value of offshore wind, solar PV and 8-hour battery storage declines as penetration increases. Thus, for every incremental MW of thermal capacity retirement, more and more renewable and storage capacity would be required to maintain the same IRM. ICF's

[23] NYISO 2019 Power Trends, pg. 23.
[24] NYISO 2020 Power Trends, pg. 26
[25] *NYISO Grid in Transition Study,* The Brattle Group. March 30, 2020.

analysis suggests that it is more economical to retain some gas-fired generation by converting them to use RNG than to continue building renewable and battery capacity.

Second, there is a need for resources that are flexible enough to perform “load-following” of more variable net load (total load less renewable generation) patterns, respond to short-term fluctuations, insure against forecast uncertainty associated with renewables, and provide grid services such as voltage support. The Project will repower the existing Danskammer generating station with a fast-ramping, fast-start, and efficient CCGT. The proposed unit will have a ramp rate of [redacted] MW per minute from a hot start, allowing it to reach its full capacity of 600 MW in less than an [redacted] By contrast, the existing Danskammer generating station has a ramp rate of less than [redacted] MW per hour and requires more than [redacted] hours of pre-boiler firing before supplying any electricity. Other steam turbines in NYS share similar characteristics to the current facility, and are thus, not suited to a future electric system with higher forecast uncertainty and near-term variability. The Project, along with other efficient CCGTs and CTs, on the other hand provides more flexible load-following capability and will also be able to provide grid services such as frequency regulation and voltage support.

Finally, RNG-fired thermal generation is projected to provide zero-emission electricity supply to New York’s grid in 2040 (see Table 4-2 and Table 4-3). In both the Base and Change cases, gas-fired capacity running on RNG generates approximately 8.5 TWh, or 6% of the state’s annual energy use. Thus, the Project, which will be the most efficient thermal unit in NYS, will displace other less efficient RNG units in NYS, and improve system efficiency. Further, due to the interconnected nature of the power grid, the Project’s zero emissions generation will help to displace conventional fossil-fuel generators in the northeast region outside of NYS, thereby reducing greenhouse gas emissions across the northeast region.

Table 4-2: Generation Mix (in GWh) in the Base Case

Capacity Type	2025	2030	2035	2040
Thermal	46,092	26,403	26,796	8,468
Nuclear	27,757	26,376	27,328	26,872
Hydro	27,626	27,626	27,626	27,627
Solar	7,567	15,243	15,166	16,376
Onshore Wind	14,600	14,540	14,550	14,451
Offshore Wind	7,045	24,803	35,108	51,852
Other Renewables	2,948	2,948	2,948	2,956
Scheduled Hydro Imports	9,965	9,965	9,965	9,994
Battery Storage	954	2,273	2,260	8,073
Pumped Storage	650	1,110	1,1191	1,992
Total (excl. pumped and battery storage)	144,250	149,015	160,678	160,587

Table 4-3: Generation Mix (in GWh) in the Change Case

Capacity Type	2025	2030	2035	2040
Thermal	46,954	27,067	27,678	8,540
Nuclear	27,757	26,376	27,328	26,872
Hydro	27,626	27,626	27,626	27,627
Solar	7,567	15,243	15,166	16,376
Onshore Wind	14,600	14,536	14,550	14,451
Offshore Wind	7,045	24,803	35,110	51,848
Other Renewables	2,948	2,948	2,948	2,956
Scheduled Hydro Imports	9,965	9,965	9,965	9,994
Battery Storage	930	2,253	2,233	8,057
Pumped Storage	555	1,094	1,191	1,986
Total (excl. pumped and battery storage)	144,463	148,564	160,371	158,664

It is important to emphasize that this analysis does not examine to the full extent the potential electric load impacts associated with the electrification of New York's energy system. The load forecast utilized in this analysis assumes achievement of the energy efficiency mandates as well as the full resource targets of the CLCPA, such as the 6 GW DG SPV target in 2025. Impacts of EV and non-EV electrification are consistent with NYISO's 2020 Gold Book Baseline scenario. Given the load forecast assumptions of this analysis, ICF's findings regarding the Project's benefits are likely conservative. If the broader economy-wide CLCPA greenhouse gas reduction targets are to be realized, electricity demand will rise significantly as space heating, transportation, and other end-use energy needs transition to electricity. As a result, more zero-emissions generation and capacity will be required in NYS. This increase is also shown in other studies published by NYISO, such as the Climate Change Report published in December of 2019 and the Gold Book High Load case, both of which predict substantial demand increases compared to demand assumptions in this analysis. With the potential for significant increases in electric load, efficient and flexible RNG-fired thermal units will be even more important to maintaining reliability in the grid.

4.2 Impact on Greenhouse Gas Emissions

ICF's assessment of the impact of the Project on GHG emissions in NYS and the northeast region[26] comprises impacts on both direct carbon dioxide emissions from the Project and upstream emissions associated with the operation of the Project.

ICF found that between 2025 and 2035, the proposed Danskammer CCGT results in a net reduction in greenhouse gas emissions in the northeast region because it will be one of the most efficient power plants. Because of the complex and interconnected nature of regional wholesale power markets, the Project has the effect of displacing generation and greenhouse gas emissions from other power plants located both inside and outside of New York. According to the state's 2016 Greenhouse Gas Inventory, imports of electricity account for 12% of total electricity sector carbon emissions.[27] Thus, by reducing electricity imports into NYS by displacing less efficient (and hence, more polluting) out-of-state generators, the Project contributes to reducing NYS's overall energy sector GHG emissions. It is also important to emphasize that since the Project will have much higher variable costs (primarily due to fuel costs) than renewable and nuclear resources, it will not displace these types of zero-emission generation.

In granting a Certificate of Public Convenience and Necessity to Cricket Valley Energy Center, a 1,000 MW gas-fired CCGT, the NYSDPS noted that while a new, efficient generating project may itself produce emissions due to its high utilization, its effect on the system as a whole is to reduce emissions: "Although the project will be a major source of air emissions, carbon dioxide production regionwide is expected to decrease."[28] Echoing this conclusion, ICF's analysis found that in 2025-35, while the Project results in an average increase in direct carbon emissions of 234,000 tons in New York, it results in an average reduction of 196,000 tons annually of direct emissions in the northeast region. That is, the reductions in direct carbon emissions in the rest of the northeast region far outweigh the increase in NYS. Similarly, since the Project has the effect of displacing less efficient generators, its operation leads to a reduction in overall fuel consumption in the northeast region (including NYS). Consequently, there is a reduction in the upstream emissions. Thus, between 2025 and 2035, the operation of the Project results in a total average decrease of upstream emissions in the northeast region of 66,000 tons CO_2e annually (using a 20-year GWP for methane emissions). Overall, between 2025 and 2035, the total average annual reduction in GHG emissions is equal to 261,000 short tons CO_2e.

In 2040, direct CO_2 emissions in NYS are zero due to thermal generators reconfiguring to RNG. However, since the Project displaces less efficient out-of-state generators that still burn natural gas, it continues to result in a net decrease in direct as well as upstream emissions in the region. Thus, in 2040, there is an overall annual reduction of 20,000 short tons of CO_2e GHG in the

[26] For this analysis, the "northeast region" comprises NYISO, ISO-NE, PJM and Ontario

[27] New York State Energy Research and Development Authority (NYSERDA), "New York State Greenhouse Gas Inventory: 1990-2016" at S-3 (July 2019). This estimate includes emissions from Electricity and Net Imports of Electricity.

[28] Case 11-E-0593, *Petition of Cricket Valley Energy Center*, Order Granting Certificate of Public Convenience and Necessity and Establishing Lightened Ratemaking Regulation at 4 (issued February 14, 2013) ("Cricket Valley Order").

northeast region. The tables below present the Project's impact on direct carbon emissions, upstream emissions, and fuel consumption.

Table 4-4: Direct CO_2 Emissions in New York and the Northeast

Year	Region	Direct CO_2 Emissions (Thousand Short Tons)		
		Base Case	Change Case	Delta
2025	New York	20,130	20,356	225
	Northeast	458,599	458,285	(314)
2030	New York	11,797	11,988	191
	Northeast	467,160	467,024	(136)
2035	New York	11,980	12,267	287
	Northeast	527,078	526,940	(138)
2040	New York	-	-	-
	Northeast	577,361	577,346	(15)

Table 4-5: Upstream CO2e Emissions in New York and the Northeast

Year	Region	Upstream CO_2e Emissions Delta (Thousand Short Tons)		
		Upstream CO_2	Upstream Methane	Total
2025	New York	25	77	102
	Northeast	(23)	(71)	(94)
2030	New York	20	64	84
	Northeast	(13)	(40)	(53)
2035	New York	30	95	125
	Northeast	(12)	(37)	(50)
2040	New York	(0)	(0)	(0)
	Northeast	(2)	(3)	(5)

Table 4-6: Fuel Consumption in New York and the Northeast

Year	Region	Fuel Consumption (Million MMBtu)		
		Base Case	Change Case	Delta
2025	New York	353.4	357.5	4.1
	Northeast	5,306.0	5,303.6	(2.4)
2030	New York	207.4	210.8	3.4
	Northeast	5,504.2	5,502.3	(1.8)
2035	New York	210.9	215.9	5.0
	Northeast	6,488.4	6,486.9	(1.5)
2040	New York	69.5	69.5	(0.0)
	Northeast	7,362.2	7,361.9	(0.3)

APPENDICES

A-1 Peak and Energy Use Assumptions

The tables below present the peak and energy demand assumptions[29] used in this study.

Net Coincident Summer Peak Demand (MW)												
Year	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**NYCA**
2020	2,649	1,937	2,712	582	1,338	2,321	2,133	645	1,427	11,299	5,037	32,080
2021	2,614	1,919	2,686	611	1,310	2,272	2,097	642	1,422	11,269	4,963	31,805
2022	2,583	1,903	2,660	637	1,282	2,230	2,069	641	1,428	11,356	4,852	31,641
2023	2,547	1,882	2,630	657	1,249	2,181	2,039	638	1,419	11,298	4,699	31,239
2024	2,512	1,860	2,596	674	1,217	2,136	2,013	636	1,412	11,253	4,560	30,869
2025	2,478	1,838	2,562	684	1,185	2,091	1,986	631	1,399	11,163	4,450	30,467
2026	2,453	1,817	2,534	688	1,158	2,056	1,966	628	1,395	11,132	4,357	30,184
2027	2,435	1,806	2,514	688	1,138	2,031	1,948	625	1,397	11,134	4,305	30,021
2028	2,430	1,801	2,507	688	1,129	2,020	1,945	626	1,402	11,187	4,282	30,017
2029	2,436	1,802	2,508	684	1,128	2,019	1,946	627	1,413	11,269	4,269	30,101
2030	2,442	1,805	2,512	683	1,132	2,022	1,955	629	1,426	11,375	4,282	30,263
2031	2,454	1,812	2,520	679	1,139	2,029	1,964	631	1,439	11,497	4,312	30,476
2032	2,466	1,814	2,524	679	1,145	2,035	1,976	633	1,455	11,624	4,358	30,709
2033	2,476	1,819	2,528	678	1,149	2,042	1,990	634	1,465	11,716	4,395	30,892
2034	2,487	1,827	2,529	677	1,154	2,047	2,006	635	1,477	11,808	4,436	31,083
2035	2,500	1,831	2,532	677	1,160	2,059	2,021	637	1,488	11,909	4,483	31,297
2036	2,510	1,838	2,537	677	1,165	2,066	2,036	638	1,499	12,001	4,551	31,518
2037	2,519	1,846	2,540	676	1,172	2,076	2,053	638	1,508	12,082	4,608	31,718
2038	2,530	1,852	2,543	678	1,179	2,087	2,070	638	1,517	12,151	4,669	31,914
2039	2,541	1,860	2,546	676	1,185	2,097	2,087	638	1,524	12,212	4,738	32,104
2040	2,551	1,867	2,549	678	1,191	2,108	2,104	638	1,527	12,238	4,759	32,210

Net Coincident Winter Peak Demand (MW)												
Year	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**NYCA**
2020	2,213	1,551	2,513	750	1,323	1,887	1,551	492	857	7,540	3,271	23,948
2021	2,201	1,542	2,507	780	1,317	1,874	1,535	492	864	7,609	3,220	23,941
2022	2,196	1,534	2,509	807	1,314	1,868	1,520	495	884	7,817	3,133	24,077
2023	2,187	1,524	2,502	831	1,310	1,858	1,504	495	894	7,927	3,058	24,090
2024	2,179	1,515	2,495	851	1,305	1,851	1,489	495	905	8,055	2,958	24,098
2025	2,172	1,508	2,485	865	1,301	1,844	1,474	494	919	8,185	2,900	24,147
2026	2,171	1,504	2,478	873	1,298	1,843	1,464	495	940	8,374	2,869	24,309
2027	2,173	1,506	2,474	878	1,298	1,845	1,462	496	962	8,557	2,872	24,523
2028	2,186	1,511	2,479	881	1,303	1,853	1,466	500	990	8,815	2,891	24,875

[29] 2020 Load & Capacity Data Report (Gold Book), NYISO, April 10, 2020.

Net Coincident Winter Peak Demand (MW)												
Year	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**NYCA**
2029	2,206	1,523	2,490	886	1,312	1,868	1,481	506	1,026	9,142	2,918	25,358
2030	2,226	1,535	2,504	891	1,321	1,885	1,500	513	1,068	9,507	2,934	25,884
2031	2,256	1,553	2,523	897	1,335	1,906	1,524	521	1,107	9,869	2,992	26,483
2032	2,289	1,570	2,549	904	1,350	1,931	1,554	530	1,150	10,244	3,061	27,132
2033	2,325	1,591	2,576	914	1,367	1,959	1,588	538	1,193	10,628	3,154	27,833
2034	2,368	1,615	2,607	925	1,387	1,990	1,627	548	1,234	11,007	3,260	28,568
2035	2,417	1,643	2,644	937	1,411	2,026	1,666	558	1,277	11,382	3,393	29,354
2036	2,467	1,672	2,682	951	1,433	2,061	1,710	569	1,305	11,746	3,539	30,135
2037	2,517	1,705	2,724	965	1,458	2,100	1,757	581	1,331	12,096	3,683	30,917
2038	2,572	1,738	2,769	981	1,485	2,140	1,805	594	1,354	12,427	3,847	31,712
2039	2,631	1,772	2,817	996	1,513	2,180	1,854	605	1,371	12,731	3,963	32,433
2040	2,689	1,809	2,864	1,012	1,541	2,222	1,903	615	1,386	13,009	4,083	33,133

Net Energy Projections (GWh)												
Year	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**NYCA**
2020	14,182	9,396	15,078	4,810	7,462	11,272	8,994	2,657	5,589	48,857	19,584	147,881
2021	14,247	9,456	15,187	5,139	7,458	11,214	8,942	2,754	5,560	49,049	19,524	148,530
2022	14,233	9,460	15,236	5,407	7,404	11,117	8,837	2,819	5,564	49,455	19,336	148,868
2023	13,993	9,311	15,049	5,586	7,226	10,837	8,601	2,835	5,443	48,400	18,625	145,906
2024	13,764	9,161	14,865	5,728	7,042	10,572	8,380	2,831	5,352	47,602	17,931	143,228
2025	13,522	8,999	14,650	5,813	6,847	10,296	8,159	2,823	5,262	46,758	17,326	140,455
2026	13,322	8,863	14,466	5,858	6,680	10,065	7,981	2,812	5,191	46,123	16,861	138,222
2027	13,159	8,756	14,325	5,872	6,544	9,882	7,851	2,807	5,155	45,809	16,644	136,804
2028	13,064	8,698	14,249	5,868	6,455	9,773	7,794	2,817	5,159	45,813	16,694	136,384
2029	13,024	8,686	14,225	5,851	6,413	9,720	7,795	2,836	5,196	46,124	16,761	136,631
2030	12,997	8,688	14,218	5,843	6,387	9,690	7,837	2,861	5,250	46,602	17,004	137,377
2031	13,010	8,724	14,244	5,838	6,380	9,689	7,890	2,890	5,315	47,201	17,337	138,518
2032	13,040	8,750	14,283	5,840	6,383	9,698	7,965	2,923	5,394	47,889	17,806	139,971
2033	13,074	8,790	14,313	5,841	6,389	9,713	8,055	2,952	5,476	48,629	18,219	141,451
2034	13,122	8,846	14,357	5,852	6,402	9,735	8,158	2,985	5,562	49,399	18,769	143,187
2035	13,185	8,904	14,410	5,865	6,422	9,771	8,254	3,017	5,653	50,198	19,383	145,062
2036	13,236	8,973	14,472	5,884	6,444	9,805	8,368	3,049	5,745	51,014	20,122	147,112
2037	13,294	9,040	14,533	5,902	6,469	9,845	8,484	3,081	5,836	51,829	20,806	149,119
2038	13,361	9,117	14,601	5,924	6,502	9,892	8,605	3,111	5,929	52,660	21,473	151,175
2039	13,443	9,194	14,678	5,942	6,537	9,947	8,736	3,141	6,023	53,477	22,265	153,383
2040	13,528	9,281	14,759	5,963	6,580	10,006	8,875	3,170	6,113	54,276	22,644	155,195

A-2 Capital Cost Assumptions

The tables below provide ICF's capital cost assumptions for new renewable and CCGT with CCS resources. The values below represent the base numbers and do not show regionalization factors.

NREL ATB 2019 Build Costs (2018$)			
Utility Solar PV	**Overnight Capital Cost ($/kW)**	**FOM ($/kW-yr)**	
2020	$1,407	$17	
2025	$1,268	$15	
2030	$1,128	$14	
2035	$1,066	$13	
2040	$1,003	$12	
Onshore Wind	**Overnight Capital Cost ($/kW)**	**FOM ($/kW-yr)**	
2020	$1,526	$43	
2025	$1,388	$42	
2030	$1,251	$40	
2035	$1,190	$38	
2040	$1,129	$37	
Offshore Wind	**Overnight Capital Cost ($/kW)**	**FOM ($/kW-yr)**	
2020	$2,927	$113	
2025	$2,487	$96	
2030	$2,112	$81	
2035	$1,795	$69	
2040	$1,525	$58	
Battery Storage	**4-Hour Capex ($/kW)**	**8-Hour Capex ($/kW)**	**FOM ($/kW-yr)**
2020	$1,186	$1,990	$30
2025	$733	$1,500	$18
2030	$496	$1,256	$12
2035	$448	$1,178	$11
2040	$399	$1,099	$10

Combined Cycle with CCS	EPA v6 Reference Case Assumptions (2018$)			
	Overnight Capital Cost ($/kW)	**FOM ($/kW-yr)**	**VOM ($/MWh)**	**Heat Rate (MMBtu/MWh)**
2020	$2,201	$34.73	$7	7.514
2025	$2,096	$34.73	$7	7.493
2030	$1,918	$34.73	$7	7.493
2035	$1,776	$34.73	$7	7.493
2040	$1,672	$34.73	$7	7.493

A-3 RNG Cost Curve Development

To model RNG as a potential future source of fuel for power plants converting to RNG as a fuel source in New York, ICF analyzed resource availability and developed a cost curve. The objective of the RNG resource assessment was to characterize the technical and economic potential for RNG as a greenhouse gas emission reduction strategy, with a focus on local and regional resources deliverable to New York State. The assessment was based on an inventory of RNG feedstocks and production volumes accessible to NYS on existing transmission pipeline infrastructure. Biomass-based feedstocks were grouped into eight categories:

- Agricultural residues
- Animal manure
- Energy crops
- Food waste
- Forestry and forest product residues
- Landfill gas (LFG)
- Municipal solid waste (MSW)
- Wastewater treatment gas (WWT) from water resource recovery facilities (WWRFs)

ICF used a mix of existing studies, government data and industry resources to estimate the current and future supply of the feedstocks. The table below summarizes some of the resources that ICF drew from in its RNG resource assessment, broken down by RNG feedstock. The data sources and assessment approach were consistent with other RNG assessments ICF has conducted, notably its national assessment of RNG potential for the American Gas Foundation (AGF)[30].

Feedstock for RNG	Resources for assessment	
Agricultural residue	• US DOE 2016 Billion Ton Report	• Bioenergy Knowledge Discovery Framework
Animal manure	• AgStar Project Database	• USDA Livestock Inventory (Cattle, Swine, etc)
Energy crops	• US DOE 2016 Billion Ton Report	• Bioenergy Knowledge Discovery Framework
Food waste	• US DOE 2016 Billion Ton Report	• Bioenergy Knowledge Discovery Framework
Forestry and forest product residue	• US DOE 2016 Billion Ton Report	• Bioenergy Knowledge Discovery Framework
LFG	• US EPA Landfill Methane Outreach Program	
MSW	• US EPA	• Waste Business Journal
WRRF	• US EPA	• Water Environment Federation

30 https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

Based on these sources, ICF then developed RNG production potential estimates incorporating a variety of constraints regarding accessibility to feedstocks, the time it would take to deploy projects, the development of technology that would be required to achieve higher levels of RNG production, and the consideration of likely project economics—with the assumption that the most economic projects will come online first. The RNG production estimates differentiate between the two biomass-based RNG production technologies currently available: anaerobic digestion and thermal gasification.

RNG Feedstock	Supply Assumptions
Agricultural residue	50% of the agricultural residue biomass available at $50/dry ton. [31]
Animal manure	60% of technically available animal manure.
Energy crops	50% of the energy crop biomass available at $70/dry ton.
Food waste	70% of the food waste available at $10/dry ton.
Forestry and forest product residue	60% of the forest and forestry product residue biomass available at $460/dry ton.
Landfill gas[32]	RNG production at 65% of the LFG facilities that have collection systems in place; 60% of the LFG facilities that do not have collections systems in place; and 80% of EPA's candidate landfills.
MSW	60% of the non-biogenic fraction of MSW available at $100/dry ton.
WRRF	50% of WRRFs with a capacity greater than 3.3 million gallons per day.

The RNG resource scenario also includes constraints based on geography and further limited by the current share of regional natural gas consumption. The scenario includes only RNG feedstocks from the U.S. eastern seaboard region, based on the EIA's Census regions of New England, Mid-Atlantic, South Atlantic, East North Central and East South Central. Available RNG resources are further limited by NYS's share of regional non-electric generation natural gas consumption, which is equivalent to roughly 10% of the region.

A comparison to the maximum technical potential of available biomass in the region that could be used to produce RNG illustrates the relative conservative nature of the RNG production

[31] Feedstock availability for agricultural residue, energy crops, forestry and forest product residue, and MSW are based on specified-price simulations for biomass used in the DOE Billion Ton Report. These price simulations introduce markets for biomass at specific farmgate or tipping fee prices, with the price driving the available volume of biomass. The higher the price, the greater the volume of economically viable biomass is available.
[32] ICF considered only landfills that are either open or were closed post-2000. This constraint was imposed to account for the fact that the phase during which the decomposition of waste in a landfill produces sufficient methane concentrations lasts about 20-25 years, and this is the period during which waste-to-energy projects are most viable.

option: the scenario total of 185 tBtu in 2040 represents roughly 2% of the total biomass available in the U.S. eastern seaboard region.

Infrastructure build out and technology development are constrained and reflected temporally. In the near term RNG production is sourced from feedstocks that use commercially available anaerobic digestion technology (landfill gas, WRRFs and animal manure). To allow time for technology and infrastructure development, RNG feedstocks that use thermal gasification do not make a significant contribution until post-2030, including agricultural residues, forestry residues and energy crops.

RNG production will require new interconnections to pipelines, but RNG supply does not necessarily require additional natural gas system infrastructure, such as transmission and distribution pipes. The assumptions that limit the potential for each feedstock are designed to reflect that not all of the feedstocks that could technically produce RNG are viable or feasible. For some feedstocks this lack of viability could be due to geography or other physical restrictions. For example, only 60% of the technically available animal manure feedstock is considered for RNG production, reflecting that the animal manure feedstock is located in rural or regional areas, and some of these locations are a long distance from existing pipelines.

Overall natural gas infrastructure is not explicitly addressed in the RNG resource assessment. ICF's general assumption is that with a steady decline in natural gas consumption over the long term, RNG coming into the pipeline system (particularly at larger volumes post-2035) will not have a huge impact on system or pipeline capacity.

ICF developed assumptions for the capital expenditures and operational costs for RNG production from the various feedstock and technology pairings. ICF characterizes costs based on a series of assumptions regarding feedstock type, production facility size, gas upgrading and conditioning costs (depending on the type of technology used, the contaminant loadings, etc.), compression, and interconnection for pipeline injection. ICF also includes operational costs for each technology type.

In relation to pipeline interconnection, ICF understands that project developers have reported a wide range of interconnection costs, with numbers as low as $200,000 reported in some states, and as high as $9 million in other states. ICF appreciates the variance between projects, including those that use anaerobic digestion and thermal gasification technologies, and its supply-cost curves are meant to be illustrative, rather than deterministic. This is especially true in the long term, because ICF does not include significant cost reductions that might occur as a result of a rapidly growing RNG. The table below outlines some of ICF's baseline assumptions employed in its RNG costing model.

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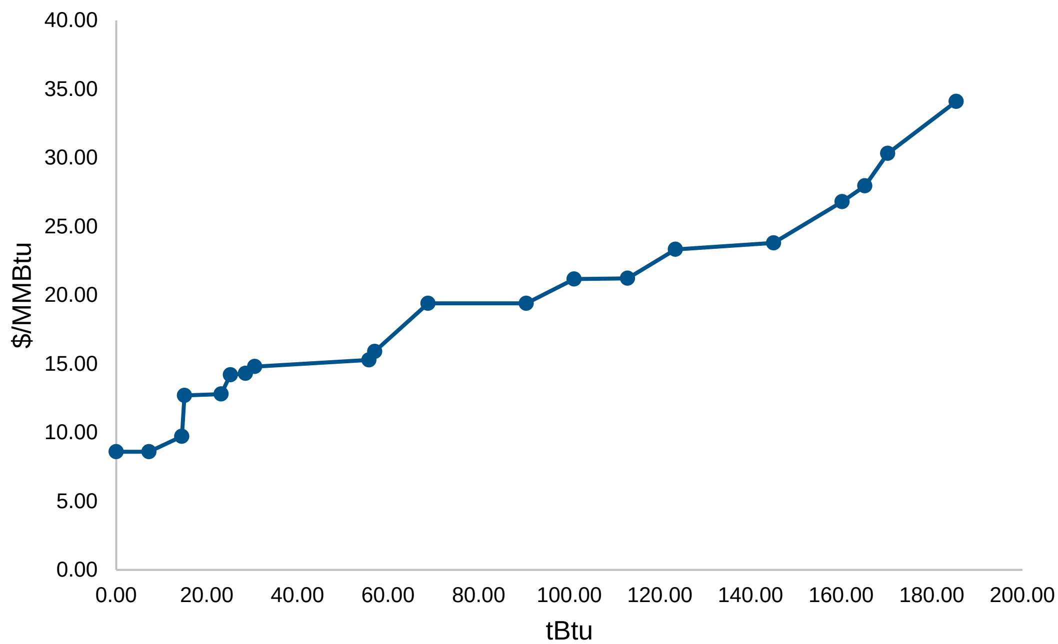
Cost Parameter	ICF Cost Assumptions
Facility Sizing	▪ Differentiate by feedstock and technology type: anaerobic digestion and thermal gasification. ▪ Prioritize larger facilities to the extent feasible, but driven by resource estimate.
Gas Conditioning and Upgradation	▪ Vary by feedstock type and technology required.
Compression	▪ Capital costs for compressing the conditioned/upgraded gas for pipeline injection.
Operational Costs	▪ Costs for each equipment type—digesters, conditioning equipment, collection equipment, and compressors—as well as utility charges for estimated electricity consumption.
Feedstock	▪ Feedstock costs (for thermal gasification), ranging from $30 to $100 per dry ton.
Financing	▪ Financing costs, including carrying costs of capital (assuming a 60/40 debt/equity ratio and an interest rate of 7%), an expected rate of return on investment (set at 10%), and a 15-year repayment period.
Delivery	▪ Cost of delivering the biogas in line with financing, constructing, and maintaining a pipeline of about 1 mile in length. The costs of delivering the same volumes of biogas that require pipeline construction greater than 1 mile will increase, depending on feedstock/technology type, with a typical range of $1–$5/MMBtu.
Project Lifetimes	▪ 20 years. The levelized cost of gas was calculated based on the initial capital costs in Year 1, annual operational costs discounted at an annual rate of 5% over 20 years, and biogas production discounted at an annual rate of 5% for 20 years.

These cost assumptions are further refined by region, including average utility costs for the electricity and natural gas used in RNG production and other factors. However, the variation of costs between regions is modest. Tipping fees are based on state-level data, and relevant for estimating costs associated with LFG and WRRFs. The table below provides a summary of the different cost ranges for each RNG feedstock and technology.

	Feedstock	Cost Range ($/MMBtu)
Anaerobic Digestion	Landfill Gas	$7.10 – $19.00
	Animal Manure	$18.40 – $32.60
	Water Resource Recovery Facilities	$7.40 – $26.10
	Food Waste	$19.40 – $28.30
Thermal Gasification	Agricultural Residues	$18.30 – $27.40
	Forestry and Forest Residues	$17.30 – $29.20
	Energy Crops	$18.30 – $31.20
	Municipal Solid Waste	$17.30 – $44.20

The chart below shows ICF's price versus quantity curve for RNG in 2040.



A-4 Hydrogen Cost Curve Development

Power-to-gas (P2G) is a form of energy technology that converts electricity to a gaseous fuel, such as hydrogen. Electricity is used to split water molecules into hydrogen and oxygen, and the hydrogen can be further processed to produce methane when combined with a source of carbon dioxide. If the electricity is sourced from renewable resources, such as wind and solar, then the resulting fuels are carbon neutral.

The key process in P2G is the production of hydrogen from renewable sources of electricity by means of electrolysis. This hydrogen conversion method is not new, and there are three electrolysis technologies with different efficiencies and in different stages of development and implementation:

- Alkaline electrolysis,
- Proton exchange membrane electrolysis, and
- Solid oxide electrolysis.

The hydrogen produced from P2G is a highly flexible energy product that can be used in multiple ways. It can be:

- Stored as hydrogen and used to generate electricity at a later time using fuel cells or conventional combustion turbine generating technologies.
- Injected as hydrogen into the natural gas system, where it augments the natural gas supply.
- Converted to methane and injected into the natural gas system.

The flexibility of hydrogen provides advantages beyond as an input to methanation for RNG. Hydrogen can be used in place of natural gas in many applications, and hydrogen can be mixed directly with natural gas in pipeline systems, although there are physical limits to the level of hydrogen blending in natural gas pipeline systems. In addition, currently most commercially produced hydrogen is derived from conventional natural gas and does not have the environmental benefits of carbon neutral hydrogen produced from P2G.

Whether hydrogen or methane is the final product, P2G offers the potential to produce carbon neutral fuels from sustainable resources and leverage existing natural gas infrastructure for long-term and large-scale storage. Competing electric energy storage options, including batteries and pumped hydro storage, are expensive as a long-term energy storage option, and can be more expensive than hydrogen storage.

ICF estimated that hydrogen would be available to supply an additional 30 Tbtu of non-emitting fuel supply to the New York market. At an expected cost of $30/MMBTU ($2019), the cost of the hydrogen supply is forecasted to be in line with the high end of the RNG supply curve and would effectively extend the available supply of non-emitting fuels available for power generation.

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A-5 Upstream Emissions Factors

ICF drew upon several public sources of data for both national and regional emissions factors to perform its analysis of the upstream emissions associated with the operation of the Project. As this section discusses below, ICF found that northeast emissions factors are much lower than national averages. However, since some detailed regional level data are not available, and to make this analysis more conservative, ICF used national level data to estimate the Project's impact on upstream emissions. The emission estimates use 2018 data, which is the most recent year for which all of the data sources are available.

Upstream GHG emissions associated with the production, processing, transportation, and distribution of the gas come from three primary sources:

- CO_2 from upstream gas combustion related to compression and processing of the gas.
- Non-combustion emissions of CO_2 extracted from the raw gas and vented at gas processing plants.
- Fugitive and vented methane emissions from across the gas value chain.

CO_2 emissions from upstream combustion are calculated from the U.S. Energy Information Administration (EIA) reporting of gas consumption in the upstream gas industry segments. Three values are reported:

- Lease gas - gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors)
- Plant gas – gas used in processing plants
- Pipeline and distribution use – gas used in pipeline and distribution system compressors

EIA reports one value for lease gas which is used in both oil and gas production. Thus, ICF prorated the lease gas consumption and related emissions between oil and gas production. The total is then divided by the EIA estimate of gas supplied to consumers (24.8 Tcf) to calculate emissions of 5.5 kg CO_2 equivalent per MMBtu of gas delivered.

Segment	Consumption (Tcf)	Emissions ($MMTCO_2$)
Lease	0.7	35.7
Plant	0.4	23.7
Pipeline and Distribution	0.9	45.8
Total	2	105.1
Gas Delivered to Consumers (Tcf)		24.8
Emission Rate (kg CO_2e/MMBtu)		5.5

Non-Combustion CO_2 is the primary non-hydrocarbon component in raw natural gas at the wellhead and is removed by simply venting into the atmosphere. The EPA Inventory of U.S. GHG Emissions[33] reports 35 $MMTCO_2$ of non-combustion CO_2 from gas processing plants, or 1.4 kg CO_2/MMBtu of gas delivered to consumers.

Fugitive and vented methane emissions from the supply chain are the largest drivers of upstream emissions in the natural gas infrastructure. Two key factors in determining the effect of a GHG are its warming effect and the length of time that it remains active in the atmosphere. CO_2 is the least potent of the GHGs but remains in the atmosphere for thousands of years. Methane, on the other hand, is more potent but has a relatively short life span of 12 years in the atmosphere. A factor called Global Warming Potential (GWP) is used to distinguish between these two factors by measuring the amount of heat a GHG traps relative to CO_2. Most countries use the Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report (AR4) which set a 100-year GWP of 25 and a 20-year GWP of 72 for methane. However, the Fifth Assessment Report (AR5) from IPCC, which was released in 2014, updated the GWP for methane by fully incorporating carbon cycle feedback. For this analysis, ICF used IPCC's AR5 20-year GWP of 86.

IPCC AR	Year Published	20-Year GWP for methane	100-Year GWP for methane
AR4	2007	72	25
AR5	2014	86	34

Source: IPCC

The 2020 EPA Inventory estimates 140 $MMTCO_2e$ of methane emissions from the natural gas sector, as summarized in the table below. Most power plants receive gas directly from interstate pipelines and do not have emissions related to an LDC. Although the proposed Danskammer CCGT will receive its fuel from Central Hudson Gas & Electric, most of the LDC emissions are related to sources such as customer meters, low pressure gas mains, and service lines, which do not apply to the Project. Thus, the upstream emissions applicable to the Project total 128.1 $MMTCO_2e$ per year, which corresponds to 17.2 kg CO_2e/MMBtu (37.9 lb CO_2e/MMBtu) of delivered gas on a 20-year GWP basis.

Segment	Emissions (MMTCO2e)
Production	47.2
Gathering	34.8
Processing	12.2
Transmission	33.9
LDC	11.8
Total	140

[33] U.S. EPA, Inventory of U.S. Greenhouse Gases and Sinks – 1990-2018. EPA 430-R-20-002.

The table below summarizes the total upstream emissions factors for this analysis based on national-level data.

Source	kg CO2e/MMBtu	lbs CO2e/MMBtu
Combustion CO_2	4.1	9
Non-Combustion CO_2	1.4	3.1
Methane (GWP=86)	17.2	37.9
Total	22.7	50

Regional Emissions Factors

ICF's decision to rely on national-level emissions factors was primarily due to a lack of disaggregated data on a regional level. In particular, non-combustion CO_2 emissions and methane inventory data are not available by region. However, ICF estimated the regional emissions factors using an estimator it developed in 2019 for New York City[34] that differentiates methane emissions by natural gas producing basin. The estimator relies on the EPA Greenhouse Gas Reporting Program (GHGRP) to calculate the regional factors based on estimates of the sources of gas for each consuming region. The table below summarizes these estimates for the regions included in this modeling exercise.

Demand Region	Supply Region	Gas Supply Breakout 2020
New York	Marcellus – PA	60%
	Canada	40%
New England	Marcellus - PA	84%
	Canada West	10%
Virginia	Marcellus - WV	25%
	Marcellus - PA	69%
	Marcellus - OH	1%
	Haynesville	1%
	Virginia	3%
West Virginia	Marcellus - WV	97%
	Marcellus - PA	3%
Pennsylvania	Marcellus - PA	100%

[34] ICF Methane Emissions Estimator Documentation, March 2019, Prepared for NYC Mayor's Office of Sustainability

Demand Region	Supply Region	Gas Supply Breakout 2020
Ohio	Marcellus - WV	14%
	Marcellus - PA	28%
	Marcellus - OH	58%
Chicago	Marcellus - WV	1%
	Marcellus - PA	1%
	Marcellus - OH	3%
	Canada West	40%
	Denver Joulesburg Basin	9%
	Southwest Wyoming/Western Utah	3%
	Cheyenne Hub	2%
	San Juan Basin	1%
	North Wyoming	4%
	Montana/North Dakota	12%
	Permian	6%
Maryland	Marcellus - WV	19%
	Marcellus - PA	81%

Source: ICF analysis.

Note: The supply breakout for some demand regions does not add up to a 100% because the model is balancing the gas supply/flows/storage constraints from nearby nodes to match the annual demand.

By picking a nominal city location within each state and applying these percentages within the methane estimator, ICF calculated the upstream methane emissions for each state using the regional GHGRP data. As before, LDC emissions were excluded. The table below summarizes ICF's regional emission factor estimates.

State	City	Emission Rate (kg CO2e/MMBtu)	Emission Rate (lbs CO2e/MMBtu)
National Average		17.2	37.9
New York	Poughkeepsie	15	33
New England	Boston	9.4	20.7
Virginia	Richmond	3.9	8.6
West Virginia	Clarksburg	6.1	13.2

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State	City	Emission Rate (kg CO2e/MMBtu)	Emission Rate (lbs CO2e/MMBtu)
Ohio	Cleveland	4.9	10.8
Pennsylvania	Philadelphia	3.2	6.6
Illinois	Chicago	15.3	33.7
Maryland	Baltimore	3.1	6.6

The regional estimates are less than the national data for all northeast regions. The differentiating factor is that lower-emitting states get most of their gas from the nearby Marcellus resource while the higher emitting states source gas from the Gulf Coast, Rockies, or Western Canada. The longer distance results in higher pipeline emissions. In addition, production in the Marcellus has lower emissions than some other regions because the wells are newer, there is less requirement for processing, and state regulations in Pennsylvania may limit emissions more than in some other regions. Thus, ICF's use of national average for this analysis makes its analysis more conservative.

Upstream Emissions for RNG

In 2040, all of the fuel used in thermal plants in NYS is RNG. As a biogenic fuel, the CO_2 emissions from combustion are assumed not to add to the atmospheric GHG loading and therefore do not create on-site GHG emissions. However, the RNG can still generate upstream emissions. These emissions can have both positive (for instance, biogas processing) and negative (for example, avoided methane emissions from landfills) carbon intensities based on the feedstock. Since NYS is assumed to be zero-emissions electricity in 2040, a complete accounting of these sources of RNG may result in net negative methane emissions. However, due to the uncertainty of the specific sources and to be conservative, this analysis does not include these net reductions, and simply assumes zero methane emissions for production and processing. Methane emissions from RNG transportation are still included, though they would be lower than for conventional gas due to shorter transportation paths.

For 2040, the upstream emissions include only methane emission factors related to gas transportation – 5.9 kg CO_2e/MMBtu (13 lbs CO_2e/MMBtu) RNG delivered to consumers. This is the national average value, as noted above, regional data would be lower.

Upstream Emissions for Coal

Upstream emissions for coal include the combustion emissions for mining, processing, and transportation and methane emissions from the coal formations. The inputs for this analysis are based on a detailed life-cycle analysis performed by the National Energy Technology Laboratory.[35] The study estimated upstream emissions of 19.8 lb CO_2/MMBtu and methane emissions of 60.5 lbs CO_2e/MMBtu (GWP=86).

[35] NETL, Life Cycle Analysis: Existing Pulverized Coal (EXPC) Power Plant, September 30, 2010. DOE/NETL-403-110809

Upstream Emissions for Oil

Upstream emissions for oil include the combustion emissions related to production, transportation, and especially refining and methane emissions primarily related to production. The combustion emissions estimates are based on a life-cycle analysis performed for the NYC Mayor's Office of Sustainability.[36] The methane emissions were taken from the EPA GHG inventory. The estimated emission factors are of 31 lbs CO_2/MMBtu and methane emissions of 14.7 lbs CO_2e/MMBtu (GWP=86).

[36] ICF, New York City Natural Gas Market Fundamentals and Life Cycle Fuel Emissions, February 2012.