Decarbonization Pathways for Southern Company Gas

September 2021

Submitted to:
Southern Company Gas

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List of Abbreviations

AGA	American Gas Association
AGF	American Gas Foundation
Bcf	Billion Cubic Feet
Btu	British Thermal Unit
CH_4	Methane
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model
GHGI	U.S. EPA Greenhouse Gas Inventory
GHGRP	U.S. EPA Greenhouse Gas Reporting Rule
GWP	Global Warming Potential
IPCC	Intergovernmental Panel on Climate Change
kg	kilogram
LDAR	Leak Detection and Repair
Mcf	Thousand Cubic Feet
MMcf	Million Cubic Feet
MMt CO_2e	Million Metric Tonnes Carbon Dioxide Equivalent
Mt	Metric Tonnes
NESCAUM	Northeast States for Coordinated Air Use Management
P2G	Power to Gas
RGGI	Regional Greenhouse Gas Initiative
RNG	Renewable Natural Gas
TBtu	Trillion BTU
UNFCCC	United Nations Framework Convention on Climate Change
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute

1 Executive Summary

Southern Company Gas Can Play a Key Role in Supporting Decarbonization Efforts in the States in Which It Operates

Southern Company Gas (GAS) engaged ICF to analyze how it can develop a pathway for decarbonization of greenhouse gas (GHG) emissions from its operations and also reduce other GHG emissions in the states in which it operates, especially customer emissions from gas consumption. This study did not attempt to optimize the overall emission reduction strategy for the states. Rather it presents different emission reduction pathways and strategies through which GAS can contribute to cost-effective reduction of GHG emissions from its own operations, from its customers, and from other segments of the state economies and also provide other benefits to its customers.

In addition, Southern Company has committed to achieve net zero direct GHG emissions from its enterprise-wide operations by 2050, which is inclusive of the operations of GAS and its four local gas distribution (LDC) companies:

- Nicor Gas in Illinois
- Atlanta Gas Light in Georgia
- Virginia Natural Gas (VNG) in Virginia
- Chattanooga Gas Company (CGC) in Tennessee

GAS also includes joint venture gas transmission and storage assets in Texas and California. The GHG reduction goals also include an aspirational target of achieving net zero methane emissions at Nicor Gas by 2030.

GAS specified the following tenets to be included in evaluating options for a decarbonization pathway for each of its utilities and for its overall operations.

- Reduction or offset to operational and owned Scope 1 GHG emissions
- GHG emissions/sustainability more broadly (Scope 2 and Scope 3)
- Alignment with long-term corporate goals
- Timing considerations for implementation
- Alignment with safety goals
- Alignment with reliability and resilience goals
- Operational feasibility and availability
- Other benefits to customers and local community (e.g., economic development)
- Existence/maturity of policy and regulatory pathway.

The analysis found that achievement of the GHG goals listed above is consistent with all of these tenets. The gas-based GHG reduction pathways identified in this analysis, if realized, would achieve the corporate net zero goal and broader sustainability benefits according to the desired timeline. These pathways preserve or enhance system safety, reliability, and resilience goals and can be achieved with technologies that are feasible and available. The pathways offer benefits beyond GHG reduction, including reduction of other pollutants, reduced energy consumption, and economic development within the service territory. While new policies and regulations may be required to enable and support these pathways, they can be addressed within the existing regulatory and policy frameworks.

The natural gas infrastructure also offers the opportunity to incorporate low-GHG energy sources such as renewable natural gas and hydrogen. This study indicates that decarbonizing the existing natural gas system and improving the efficiency of the end use gas equipment owned by customers could be a faster, less expensive pathway to reducing GHG emissions than policy-driven mandatory electrification policies that would require major restructuring and rebuilding of energy supply infrastructure and broader replacement of customer equipment. Each of these findings is discussed in this report.

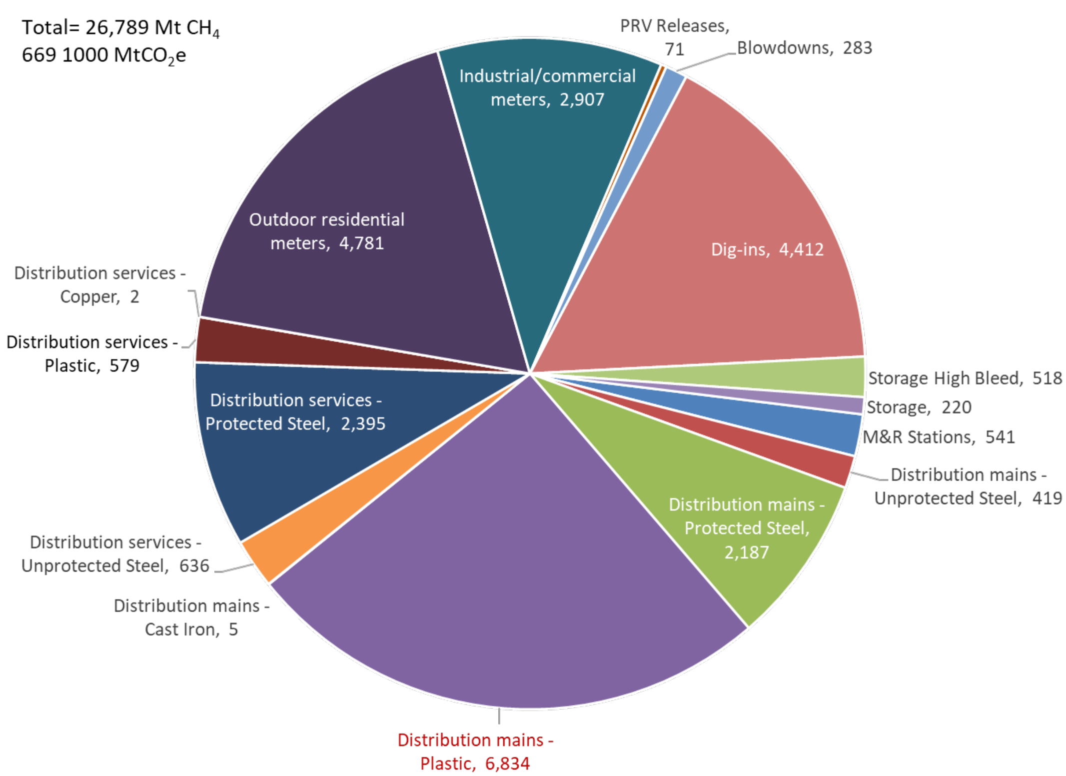
GAS' Direct Emissions are a Very Small Part of the GHG Inventories in the States

GAS' direct GHG emissions from operations include the following:

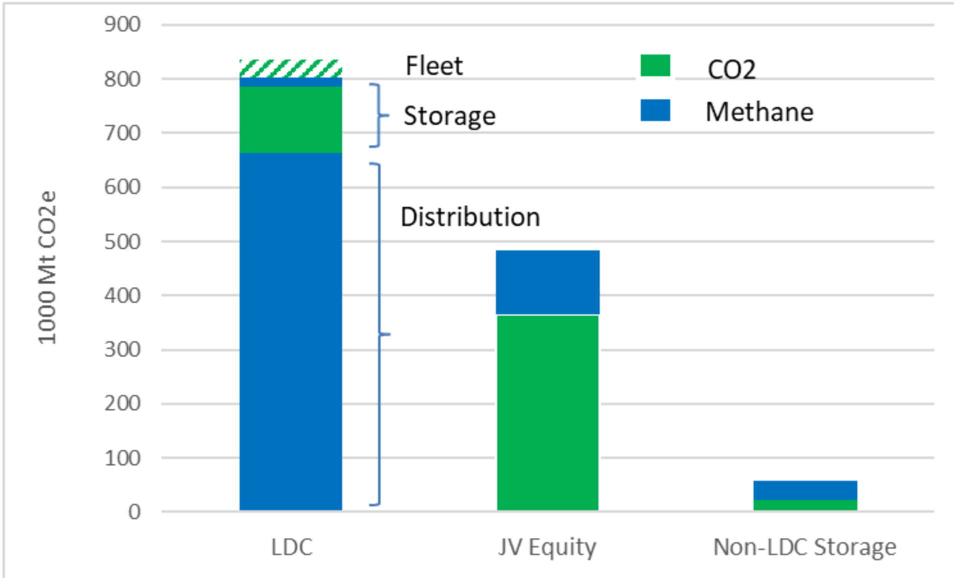
- Fugitive and vented methane emissions from operations at the distribution facilities.
- CO_2 emissions from combustion at distribution operations and fleet vehicles.

Fugitive and vented emissions of methane are the largest component of the direct emissions from the LDC operations.

Estimated GAS Methane Emissions – 2019 (Mt CH_4)



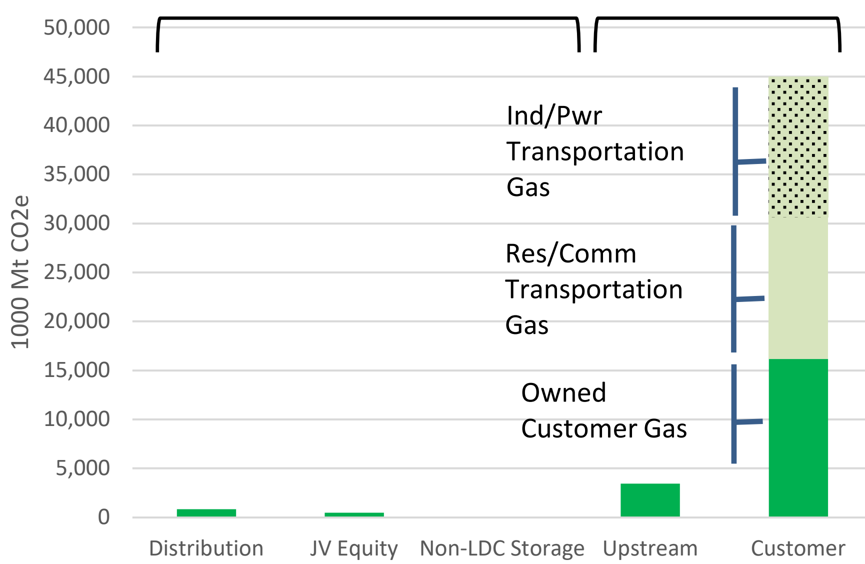
GAS Direct Emissions - 2019 (1000 Mt CO_2e)



In addition to the direct emissions from operations, there are also indirect emissions, including the following primarily energy-related sources:

- Emissions from power plants that supply electricity used by GAS.
- Upstream emissions from the production, processing, and transportation of gas that is owned and sold by GAS.
- Emissions from customer use of gas delivered by GAS LDCs.

GAS Direct and Indirect Emissions - 2019 (1000 Mt CO_2e)



Emissions related to customer gas use are several orders of magnitude larger than any of the other sources, almost 45 million Mt CO_2e ($MMtCO_2e$) based on the total volume of gas delivered to customers as tabulated and reported to the U.S. Energy Information Administration on Form

176.[1] Roughly one third of the customer emissions are from gas owned and sold by GAS versus gas purchased from other sources by customers and delivered by GAS. The upstream emissions cited in this report only include gas owned and sold by GAS because GAS does not control and cannot track the emissions from gas provided by other entities, consistent with the WRI/WBCSD GHG reporting protocol.

In all cases, the direct emissions from each LDC are less than 1% of the estimated relevant state GHG inventory and range between less than 1% to 5% of the estimated state methane emissions inventory.

Renewable Natural Gas Can Provide Environmental and Economic Benefits to GAS' Customers

Renewable natural gas (RNG) is derived from biomass or other renewable resources and is pipeline-quality gas that is fully interchangeable with conventional natural gas. On a combustion basis, RNG is considered to be a biogenic, CO_2-neutral fuel, for example by the U.S. EPA GHG emissions inventory and Greenhouse Gas Reporting Program and GHG emission trading programs. That is, the CO_2 released from combustion is CO_2 that was previously absorbed by plants from the atmosphere and there is therefore no net increase in atmospheric CO_2. In this study ICF considered three RNG production technologies: anaerobic digestion, thermal gasification, and methane production from hydrogen (for this study, we refer to this resource as "power to gas" or P2G and RNG). ICF prepared three RNG scenarios for RNG supply projections based on a variety of publicly available data sources. Accessing these RNG resources will require project and infrastructure development and regulatory support; however, RNG can provide a significant contribution to mitigation of direct and indirect emissions, especially for Nicor Gas and Atlanta Gas Light. The RNG potential for CGC and VNG is lower due to their smaller, urban service territory footprint; however, there is strong RNG potential in those states outside of the service territories.

In addition to providing a CO_2-neutral fuel at the point of use, RNG development provides environmental benefits by converting organic waste into a useful fuel and avoiding the release of these wastes and associated byproducts into the environment. Notably it avoids the release of methane from these wastes directly into the environment as a GHG. It also displaces current use of fossil-based natural gas for uses including thermal use, electricity generation, and use as a transportation fuel. RNG development operations also create construction and operation jobs and secondary economic benefits, especially in the agricultural sector, which is an important industry especially in the states in which GAS operates.

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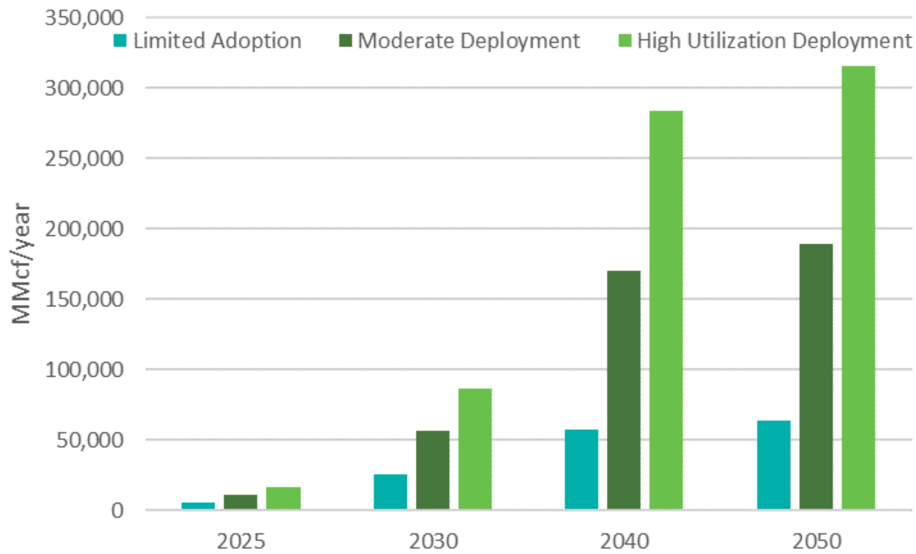
[1] Emissions from customer use of gas are also reported under the EPA GHGRP subpart NN, however the EPA excludes emissions from certain large customers in that report to prevent double counting in its reporting program. On the other hand, according to the current WRI/WBCSD GHG Protocol, GAS' Scope 3 emissions would be limited to the gas owned and sold by GAS, which is more limited than the subpart NN reported emissions approach, which does not make this distinction. To date, Southern Company has used the subpart NN reported emissions in its reporting to the Carbon Disclosure Project but generally adheres to the WRI/WBCSD GHG Protocol. Southern Company system's GHG emissions are calculated using the equity share approach presented in the WRI/WBCSD GHG Protocol for all of its owned facilities. For purposes of this study, ICF utilized the EIA Form 176 approach to take as expansive a view as possible of all customer emissions associated with gas transported by GAS and identify opportunities to reduce those emissions, but also broke out gas owned and sold by GAS to provide a better picture of those more limited actual Scope 3 emissions.

Growth Scenarios for Annual RNG Production in GAS Service Territories (MMcf/y)



When methane is captured from RNG projects, it can sometimes be registered as creditable GHG offsets according to rigorous protocols including the U.N. Clean Development Mechanism, Verra, the American Carbon Registry, and the Climate Action Reserve. These protocols ensure that the offsets are based on real and verifiable reductions that would not have otherwise been achieved. These offsets can be used to mitigate direct emissions such as methane from operations or to offset emissions from combustion.

Another renewable gas option is the use of hydrogen produced through electrolysis with renewable-sourced electricity. The hydrogen produced in this way is a highly flexible energy product that can be:

- Stored as hydrogen and used to generate electricity at a later time using fuel cells or conventional generating technologies,
- Injected as hydrogen into the natural gas system, where it augments the natural gas supply, or;
- Converted to methane and injected into the natural gas system (P2G).

Southern Company is actively engaged in the research and development of new approaches for the production and use of hydrogen. ICF projected the availability of P2G for GAS based on several renewable electricity scenarios, resulting in 27,900 to 69,850 MMcf per year of P2G by 2050.

There is a Pathway for GAS to Achieve Net Zero Direct GHG Emissions

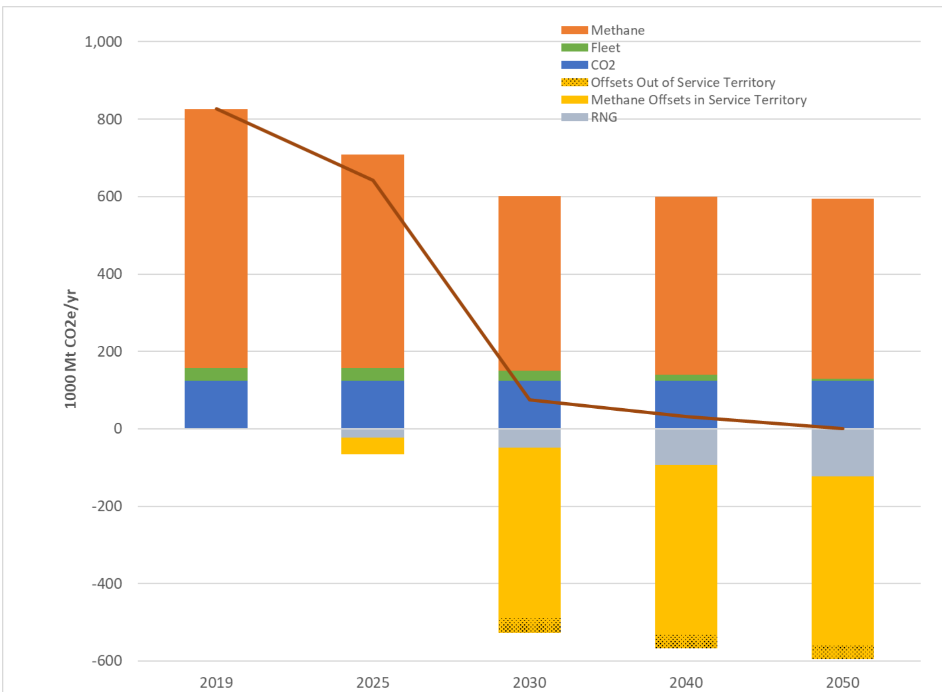
There are available and cost-effective options to reduce the methane emissions that comprise the largest source of GAS' direct emissions. These include direct measures to replace higher-emitting vintage pipe, leak detection and repair programs, and more accurate measurement protocols to replace the fixed emission factors currently being used to estimate emissions. The table below shows the potential for a 33% reduction in baseline methane emissions. The remaining methane emissions would be mitigated through the use of methane capture offsets from RNG projects.

Summary of Potential GAS Methane Reductions (Mt CH_4)

	Pipes	Meters	Dig-Ins	Blowdowns	M&R Stations	Storage	LDC Total
Baseline	13,057	7,687	4,412	283	612	702	26,753
Reductions	1,018	6,150	864	212	136	518	8,898
Remaining	12,039	1,537	3,547	71	476	184	17,854

The figure below shows the pathway for mitigation of direct emissions through direct reductions of methane emissions, fleet emissions, and the use of methane capture offsets and RNG to fuel storage compressors. It projects a 28% reduction in total direct emissions by 2050. Net zero methane emissions are achieved by 2030 including methane capture offsets from RNG projects. The pathway achieves net zero for all direct emissions by 2050 with RNG/P2G and methane capture offsets. Some offsets from outside the service territory are required for CGC and VNG.

Illustrative Direct Emissions Reduction Pathway (1000 Mt CO_2e)



There is a Pathway for GAS to Reduce or Offset its Indirect GHG Emissions

The largest source of indirect emissions was the emissions from customer use of gas. Indirect emissions from upstream methane emissions and CO_2 from combustion were much lower than the customer emissions. The upstream emissions could be addressed through the purchase of gas from entities who commit to reduce their emissions, displacement of geologic natural gas with lower carbon fuels, and through other carbon offset measures. ICF analyzed four scenarios to address decarbonizing customer emissions from the residential and commercial sectors to consider and compare the cost and GHG emissions reduction implications for each scenario to 2050:

- Scenario 1 – Conventional Efficiency Options/RNG - Customers install high efficiency gas furnaces or boilers by 2050 with RNG. Buildings get air sealing and add attic insulation by 2050.
- Scenario 2 – High Efficiency Gas Technology/RNG - Implementation begins in 2025. Natural gas heat pumps start being adopted in 2025. Buildings get deep energy retrofits by 2050 and air sealing/ attic insulation. This pathway also includes displacement of conventional geologic natural gas with RNG based on the RNG resource assessment.
- Scenario 3 – Policy-Driven Mandatory Electrification - All-electric equipment is required for new construction as of 2025. Conversion to electric space and water heating required for replacements starting in 2030. Buildings get deep energy retrofits by 2050 and get air sealing/ attic insulation.
- Scenario 4 – Gas/Electric Hybrid Technology/RNG - Starting in 2023, air-conditioning units get replaced with Air-Source Heat Pumps, forming hybrid-heating systems with the existing gas furnace. Buildings get deep energy retrofits by 2050 and air sealing/ attic insulation. The gas back-up reduces winter peak electric demand.

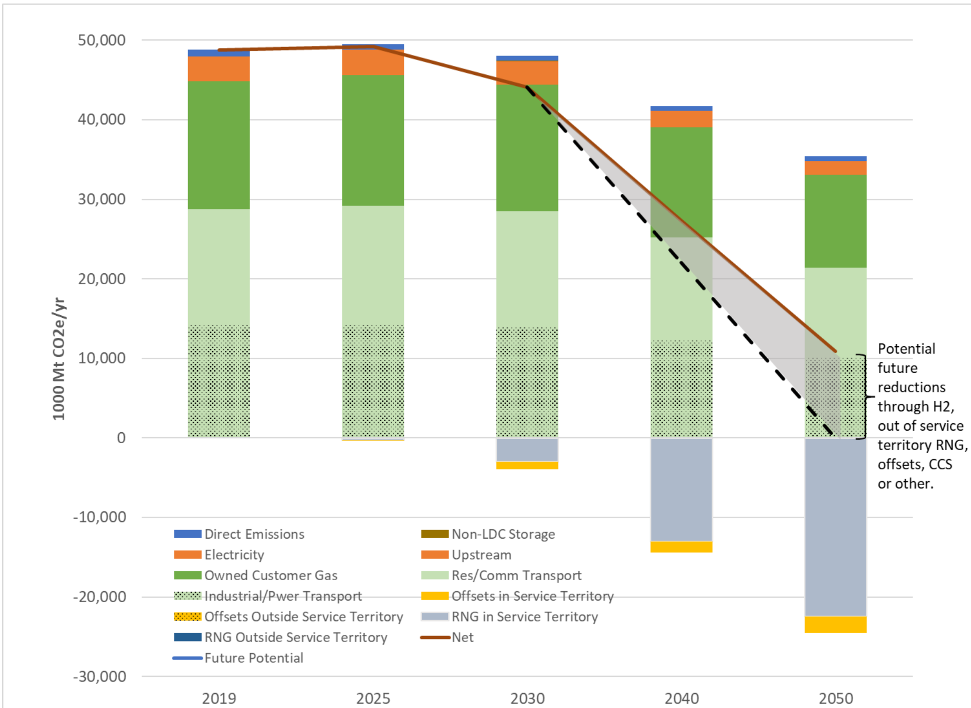
Under Scenario 3, ICF modeled a scenario of policy-driven mandatory electrification of space and water heating, which is being discussed by some stakeholders. This scenario included achievement of net zero emissions for the electric generating sector by 2050. Under Scenario 4, natural gas was used as a back-up to electric heating systems to reduce winter electric demand peaks, which can have a large effect on electric system infrastructure requirements. The analysis found that the cost of GHG reduction ($/tonne reduced) is about twice as high for the mandatory electrification scenario as for the gas scenarios.

Summary of Customer Scenario Analysis

	2020	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
	Base Year	Conventional Efficiency Options	High Efficiency Gas Technologies	Policy Driven Mandatory Electrification	Gas/Electric Hybrid Approaches
2050 Gas Consumption (Million MMBtu)	580	524.60	419.92	128.54	297.76
2050 Reduction in Gas Consumption vs. 2020 Base Year (%)		-4%	-23%	-76%	-45%
2050 Reduction in Gas Consumption vs. 2050 Reference Case (%)		-18%	-34%	-80%	-53%
2050 GHG Emissions (million tCO_2 / year)	30.8	5.16	0.53	6.82	0.08
2050 Reduction in GHG Emissions vs. 2020 Base Year (%)		-82%	-98%	-76%	-100%
2050 Reduction in GHG Emissions vs. 2050 Reference Case (%)		-85%	-98%	-80%	-100%
Total Costs - NPV of Equipment and 2020-2080 Incremental Energy Costs ($2020 Millions)		$112,020	$129,411	$228,168	$171,321
NPV of 2020 to 2080 GHG Emission Reductions (million tCO_2)		430	495	391	502
Emission Reduction Costs ($/$tCO_2$)		$260	$262	$584	$341

After reviewing the results of the analysis of the four scenarios, ICF developed a reduction pathway, shown in the figure below. This illustrative pathway shows the potential reductions of the total direct and indirect GHG emissions with the direct emission reduction pathway discussed above and the Scenario 2 High Efficiency Gas Technology/RNG results for the residential and commercial sectors.

Illustrative Total Emissions Reduction Pathway (1000 Mt CO_2e)



In addition to the actions for the residential/commercial sector the pathway also assumes energy efficiency improvements and RNG use for the industrial and fleet sectors. As expected, the customer emissions were the largest share of the emissions. This pathway analysis includes emissions from all of GAS' customers' use of gas, which is beyond GAS' Scope 3 emissions under applicable GHG protocols, which only include gas owned and sold by GAS. This pathway shows a 27% reduction in direct and indirect emissions from 2019 levels by 2050 and a 78% reduction in net emissions including methane capture offsets and RNG. This pathway projects that GAS can be net zero in 2050 for 97% of its direct emissions, upstream emissions, and emissions from gas owned and sold by GAS plus additional reductions for transportation gas at Nicor Gas and Atlanta Gas Light. The pathway shows that GAS has an opportunity to get to net zero for its direct and indirect emissions. The GAS utilities could work with their customers and the third party sellers of the gas on its system to support the reduction of the remaining emissions attributable to gas that is sold by third parties, roughly 10 MMt CO_2e. Opportunities include hydrogen, RNG, combined heat and power, offsets from other sources, or use of carbon capture and sequestration.

The Natural Gas Pathways Offer Additional Consumer Benefits

These pathways emphasize energy efficiency, which reduces consumer costs and energy consumption. These pathways also make use of the extensive, reliable, and resilient natural gas energy system that is already in place.

The Natural Gas Pathways Are Projected to be More Cost-Effective Than the Modeled Mandatory Electrification Scenario

The combination of energy-efficient building measures, high efficiency gas heating equipment, and RNG could provide greater GHG reductions for residential and commercial customers at a lower cost to customers resulting in a cost of reduction ($/tonne CO_2e), roughly half that of the policy-driven, mandatory electrification scenario modeled here.

This is true even assuming a rapid, deep electric grid decarbonization scenario leading to net zero grid emissions by 2050. If the electric grid is not decarbonized as fully or as quickly, the emission reductions would be reduced. The replacement of the natural gas energy supply with electricity would require major development of electric generating, transmission, and distribution infrastructure at a time when the electric grid is also decarbonizing, which could have implications for electricity cost, reliability, and resiliency.

Regulatory and Policy Actions Will be Necessary to Support this Transition

Regardless of how decarbonization is achieved, it will require regulatory and policy actions to enable and support it. Decarbonization will result in changes to the energy economy and changes to the energy cost structure. Consistent with their current mission, regulators will need to ensure that costs are equitably distributed between customer classes and that low-income customers are not unfairly burdened.

New Technologies Will Continue to Play a Role and Should be Enabled Through Flexible Policy Approaches

While the pathways defined here achieve the desired goals, there will certainly be new technologies developed over the next 30 years that will assist in meeting the goals. Plans and programs should be flexible enough to incorporate these technologies as they come along. Allowing for multiple future pathways, technology flexibility, and customer choice is more likely to result in cost-effective and efficient emission reductions than fixed, mandatory technology requirements. The emission reduction approach that will best meet the needs of the states and their citizens is likely to change over time and should be able to adapt to future regulatory structures, market developments, consumer needs, and technology developments.

2 Introduction

Southern Company Gas (GAS) engaged ICF to analyze how it can develop a pathway for decarbonization of its greenhouse gas (GHG) emissions from its operations and also reduce other GHG emissions in the states in which it operates, especially customer emissions from gas consumption. GAS' parent company Southern Company has committed to achieve net zero direct GHG emissions from its enterprise-wide operations by 2050, which is inclusive of the operations of GAS and its four local gas distribution companies:

- Nicor Gas in Illinois
- Atlanta Gas Light in Georgia
- Virginia Natural Gas (VNG) in Virginia
- Chattanooga Gas Company (CGC) in Tennessee

GAS also includes joint venture gas transmission and storage assets in Texas and California. The GHG reduction goals also include an aspirational target of achieving net zero methane emissions at Nicor Gas by 2030. This report analyzes how GAS can achieve these goals and also reduce its indirect emissions, especially customer emissions from gas consumption, and contribute to GHG reductions in other sectors in these states. The main body of this report focuses on the GAS aggregate characteristics. Information specific to the individual companies is included in the Chapters 10 through 13.

2.1 Policy Background

Natural gas produces the lowest GHG emissions of any fossil fuel and has played a major role in reducing U.S. GHG emissions, particularly by displacing higher-emitting coal in the power sector. Nevertheless, gas combustion does produce CO_2 and the main constituent of natural gas, methane, is a GHG in its own right. As such, there is continuing pressure to reduce climate impacts across the entire natural gas chain.

Energy-related emissions continue to be a focal point in the policy and legislative arenas. This focus has been renewed at the federal level in part as a result of the United States' renewed commitment to the Paris Climate Agreement. As part of the United States' nationally determined contribution (NDC), which is required under that agreement and represents a country's emission reduction commitment, the Biden administration has announced that the U.S. will target a 50-52% reduction in economy-wide GHG emissions by 2030 versus 2004 levels.[2] President Biden's "Build Back Better" agenda aims for a CO_2 emissions-free electric power sector by 2035 and a GHG-neutral economy by no later than 2050.[3] Separately, the EPA regulatory agenda lists an October 2021 target to propose first-time methane limits on existing oil and gas infrastructure (Reg. 2060-AV15), a companion rule to the methane rule for new oil and gas

[2] "The United States of America Nationally Determined Contribution", April 21, 2021 https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/United%20States%20of%20America%20First/United%20States%20NDC%20April%2021%202021%20Final.pdf

[3] https://joebiden.com/clean-energy/

sources that Congress has revived via the Congressional Review Act.[4] The agenda also lists an October 2022 target for finalizing the rule. The U.S. Department of Energy has also announced that it will begin the process of amending energy conservation standards and rulemakings to reduce the use of fossil fuels in federal buildings.

As a mechanism to address the impacts of climate change and promote the necessary reduction of economy-wide GHG emissions to meet these goals, there is a continued focus on integrating pricing into climate policy. Pricing policies for at least some sectors have already been adopted by a number of states, for example through emission cap and trade programs in the Northeast (RGGI) and the California cap and trade program. In the 116th Congress (2019-2020), there was significant activity on climate-related legislation. Several bills that were introduced focused on an economy-wide carbon tax. These proposals typically impose an initial economy-wide price on GHGs, e.g., dollars per ton of CO_2e, with varying degrees of escalation each year until the proposal's specific national emission reduction targets are achieved. The proposals contemplate initial pricing in a range from \$15/ton to \$52/ton and increase annually at varying rates. A clean energy standard has also been proposed for the electricity sector. Whether through a tax, a cap, or another mechanism, such policies will have economic effects on energy providers and consumers.

In addition, the White House and EPA announced in February 2021 that the Interagency Working Group on Social Cost of Greenhouse Gases has established Interim values for the Social Cost of Carbon, Nitrous Oxide and Methane, as directed by President Biden's EO 13990, and would be publishing final values by January 2022.[5] For these interim values, which are based on inflation-adjusted costs of carbon from the Obama Administration, the social cost of carbon would be \$51/ton, with methane and nitrous oxide at \$1,500/ton and \$18,000/ton, today, respectively. These would rise to \$85/ton for CO_2, \$3,100/ton for methane and \$33,000/ton for nitrous oxide by 2050. While these costs are not the same as a carbon tax, the ultimate figures will be incorporated into decisions across the federal government, including what sort of purchases it makes, the kind of pollution controls it establishes for industries, and which highways and pipelines may be permitted to be built in the years to come.

A carbon fee and other regulatory and policy requirements for gas-related GHG emissions would change the cost of operations for gas distribution companies, including direct compliance and procurement costs. They would also affect gas customers in the residential, commercial, and industrial sectors through the cost of gas or actual limits on its use.

At the local level, there are proposals and regulations in other parts of the country to ban the use of natural gas in new buildings and/or to phase out its use over time.

In the face of increasing recognition of the effects of climate change and the potential and actual development of policy and regulatory initiatives as discussed above, Southern Company, the

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[4] EPA Agency Rule List – Spring 2021
https://www.reginfo.gov/public/do/eAgendaMain?operation=OPERATION_GET_AGENCY_RULE_LIST&currentPub=true&agencyCode=&showStage=active&agencyCd=2000&csrf_token=431560A2E0F16C291276625AE64852EDF5D0A1A2A801CE24E4EC142E0DCCA665BD42A6D4FEEBF297281D925CD739F865C41E

[5] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

parent company of GAS, has set GHG emissions reduction goals across all electric and gas operations.[6] In addition to considering investments to reduce direct and indirect emissions, GAS is exploring CO_2-neutral gaseous fuels, such as renewable natural gas (RNG) and hydrogen, and has committed to reducing GHG emissions even further through smart innovation, energy efficiency, new and modernized infrastructure, and advanced technologies that provide reliable, resilient, and affordable energy service choices for consumers.

As these measures reduce GAS' direct and indirect emissions, they will also reduce GAS' customers' exposure to increased GHG policy costs as their direct and indirect GHG footprints are reduced. The analysis in this report projects that such reductions can be achieved at a lower reduction cost than other decarbonization options modeled or reviewed, by taking advantage of the existing natural gas infrastructure in conjunction with energy efficiency, new technology, and CO_2-neutral gaseous fuels.

2.2 Description of LDC Operations

Customer and Sales Mix

Most of the GAS LDC customers purchase both the gas commodity and the delivery service from the utilities as bundled sales service. Some customers purchase only the delivery or transportation service and rely on another supplier or marketer for the gas commodity. Table 1, Figure 1, Figure 2, and Figure 3 summarize the distribution of customers and deliveries for GAS by customer segment and separate those customer segments by bundled commodity and delivery service customers (identified as "sales" customers) and customers who receive only delivery service (identified as "transportation" customers). (Sales for vehicle use are included in the commercial category.) While transportation customers comprise 45% of the customer count, they consume 64% of the volume. Residential customers account for 93% of the customer count but only 45% of the volumes.

Table 1 - GAS Sales and Deliveries - 2019

		Residential	Commercial	Industrial	Electric	Total
Sales	Customers	2,170,723	142,179	12,358	42	2,325,302
	Consumption (Mcf)	231,070,611	56,457,176	9,374,998	2,911	296,905,696
	Mcf/Customer	106	397	759	69	1,331
Transportation	Customers	1,743,556	137,282	7,826	17	1,888,681
	Consumption (Mcf)	138,311,096	126,476,291	192,755,546	70,360,597	527,903,530
	Mcf/Customer	79	921	24,630	4,138,859	4,164,489
Total	Customers	3,914,279	279,461	20,184	59	4,213,983
	Consumption (Mcf)	369,381,707	182,933,467	202,130,544	70,363,508	824,809,226

[6] https://www.southerncompany.com/clean-energy/net-zero.html

Figure 1 - Ownership of Delivered Gas - 2019 (MMcf)

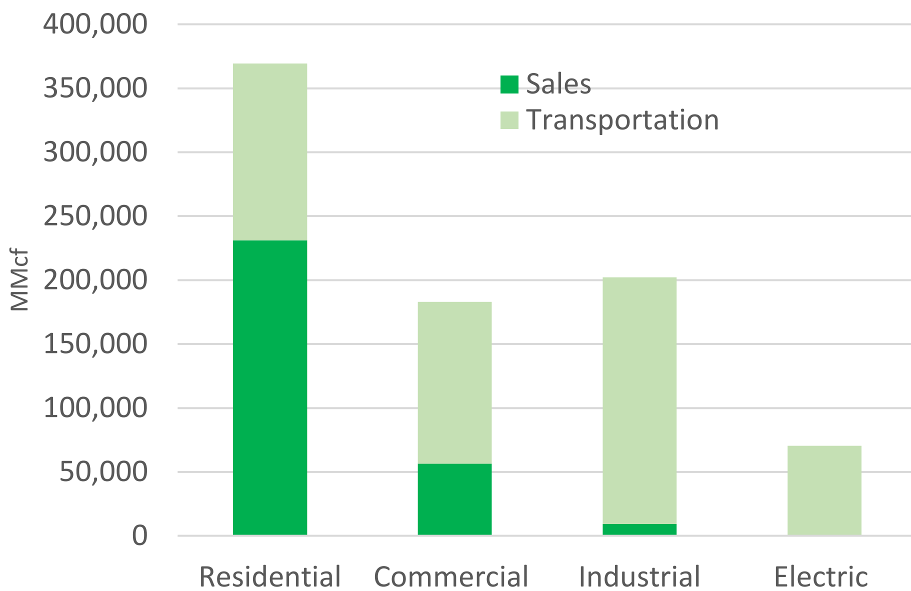
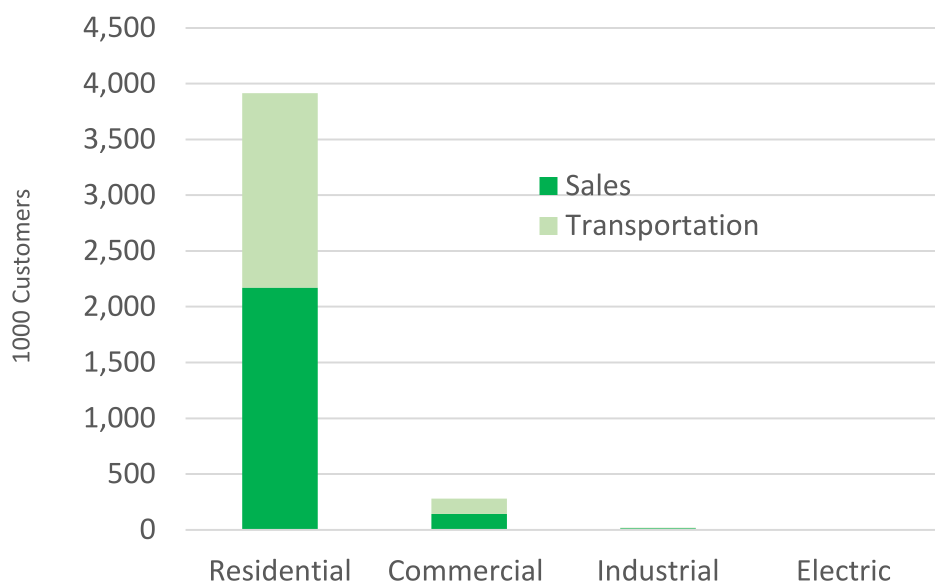
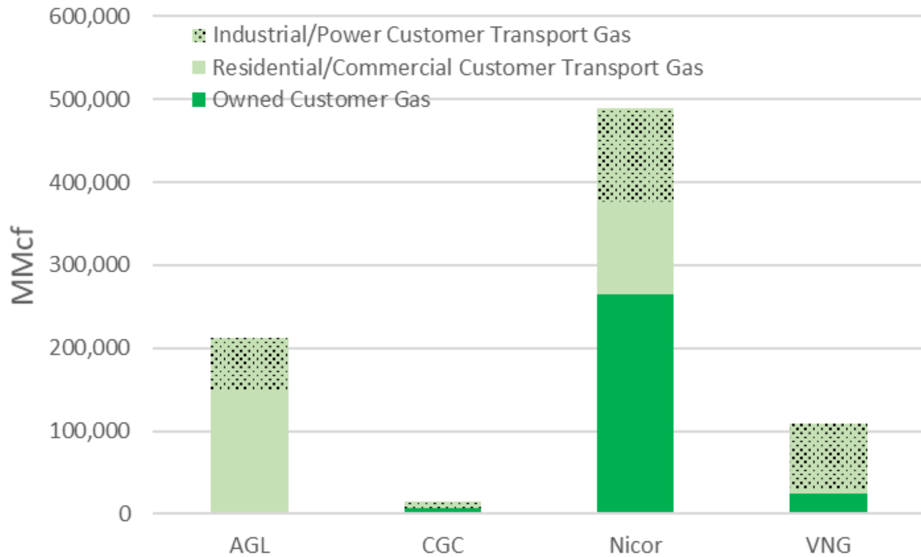


Figure 2 - Gas Customer Distribution – 2019 (1000 Customers)



Nicor Gas delivers almost 60% of the total GAS volumes and almost half of the volumes are transportation service (Figure 3). Atlanta Gas Light is the second largest in terms of delivery; its volume is entirely transportation service. Although much smaller overall, over 60% of VNG deliveries are transportation service to electric generators. Overall, the majority of the GAS volumes, 64%, are transportation service. This could be important for the use of alternative low GHG fuels, such as RNG or hydrogen. Although GAS has a role to play in supporting the deployment of these alternative GHG fuels and promoting the development of RNG projects, these efforts will require partnership among GAS, the marketers, and their transportation customers.

Figure 3 – 2019 GAS Delivery Breakdown by Company (MMcf)



Calculation of GHG Emissions

The study relied on several different sources and methodologies to estimate GAS' 2019 baseline GHG emissions. The largest component of direct emissions was fugitive and vented methane. These emissions were estimated using methodologies established by the U.S. EPA. These methodologies use an activity factor (miles of pipe, number of meters, etc.) times a fixed emission factor set by the EPA. This approach is relatively easy to apply but does not recognize emission reductions programs such as leak reduction that do not involve replacing equipment or reducing equipment counts. The emission factors are based on limited and sometimes older studies and may not be accurate for all situations. These limitations are leading some companies to develop direct measurement programs and or company-specific emission factors that are more accurate and reflective of emission reduction programs.

Most of the CO_2 emissions estimates were calculated from measured fuel consumption and CO_2 emission factors for each fuel. This applies to fleet vehicle use and energy use in company buildings or in compressors or generators at buildings and operating facilities.

The emissions from customer use of gas are by far the largest source emissions related to GAS' business. These emissions are classified as Scope 3 according to the WRI/WBCSD GHG reporting protocol. [7] However, the WRI/WBCSD definition includes only gas that is owned and sold by GAS, and so excludes emissions related to transportation gas. The estimates of emissions from customer use of gas for this report were calculated from the customer gas deliveries tabulated and reported by the company to the U.S. Energy Information Administration. This is the most complete depiction of deliveries and customer emissions for understanding the full opportunities for reduction of customer emissions, but includes emissions beyond GAS' Scope 3 emissions, which would be limited to the gas owned and sold by GAS according to the current WRI/WBCSD GHG Protocol.

[7] The World Resources Institute and World Business Council for Sustainable Development have established the standard GHG account principles that are used by many companies and governments.

Emissions from customer use of gas are also reported under the EPA Greenhouse Gas Reporting Rule (GHGRP) subpart NN, however the EPA excludes emissions from certain large customers in that report to prevent double counting in its reporting program. On the other hand, according to the WRI/WBCSD GHG Protocol, GAS' Scope 3 emissions would be limited to the gas owned and sold by GAS, which would be more limited than the subpart NN reported emissions approach, which does not make this distinction.

To date, Southern Company has used the subpart NN reported emissions in its reporting to the Carbon Disclosure Project but generally adheres to the WRI/WBCSD GHG Protocol. For purposes of this study, ICF utilized the EIA Form 176 approach to take as expansive a view as possible of all customer emissions associated with gas transported by GAS and identify opportunities to reduce those emissions, but also noted that there are more limited actual Scope 3 emissions.

The data driving all of these calculations, including equipment counts, emission factors, and fuel consumption, change over time and are sometimes updated and revised in future years as better data becomes available. Such updates can result in revisions to the historical estimates of CO_2 emissions. Similarly, EPA sometimes updates the emission factors used to calculate methane emissions, as it recently did for industrial and commercial customer meters. When these factors change, it can result in updates to historical estimates and or sudden changes in year over year emission estimates.

GHG Emissions

GAS' direct GHG emissions included:

- Fugitive and vented methane emissions from operations at the distribution and storage facilities.
- CO_2 emissions from combustion at distribution and storage operations and from fleet vehicles.
- GHG emissions from Joint Venture operations.

GAS' direct emissions totaled 1,319 thousand Mt CO_2e in 2019 including JV Equity sources and non-LDC storage. The emissions from the four LDCs was 836 thousand Mt CO_2e. The largest component was methane emissions from the distribution operations. That said, GAS estimates that it has reduced annual methane emissions from its distribution system from 1998 to 2018 by approximately 50% — even as the system grew by more than 20%. The second largest LDC emission component was emissions from the storage facilities, primarily CO_2 from gas-fired compressors and electric generators. The CO_2 emissions from vehicle fleets is the third, much smaller piece. For the JV Equity and non-LDC storage, the largest component was CO_2 from compressors and other on-site equipment.

Figure 4 - GAS Direct GHG Emissions 2019 (1000 Mt CO_2e)

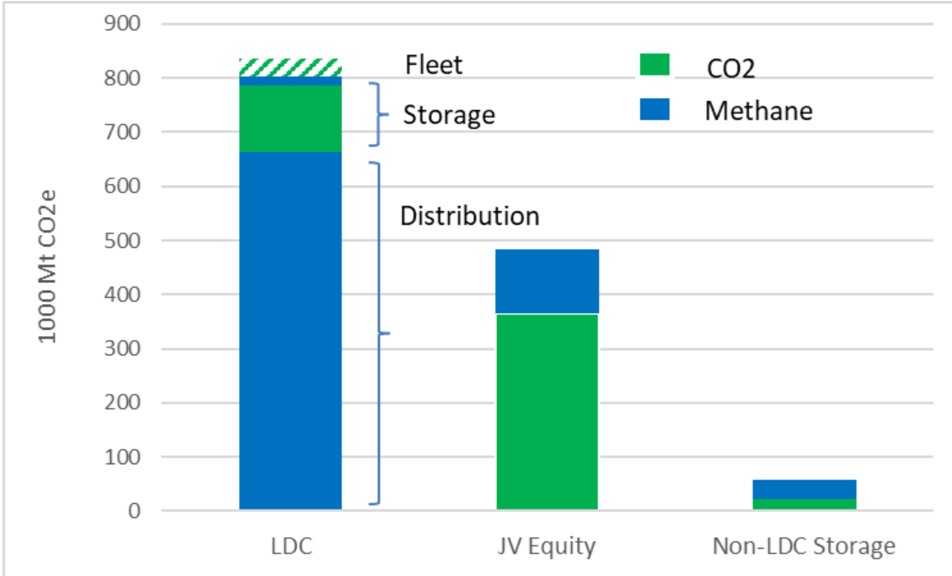
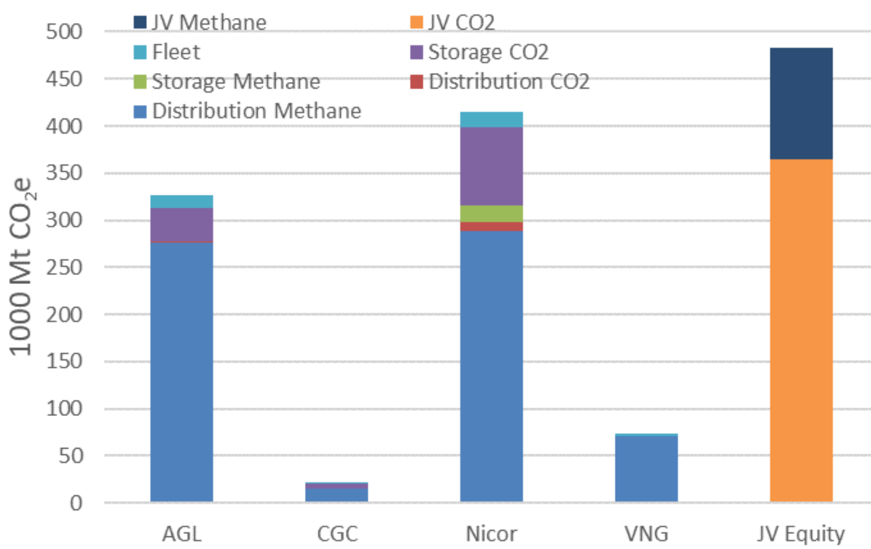


Figure 5 shows the direct emissions by company. The distribution roughly follows the GAS total as distributed by size of each LDC.

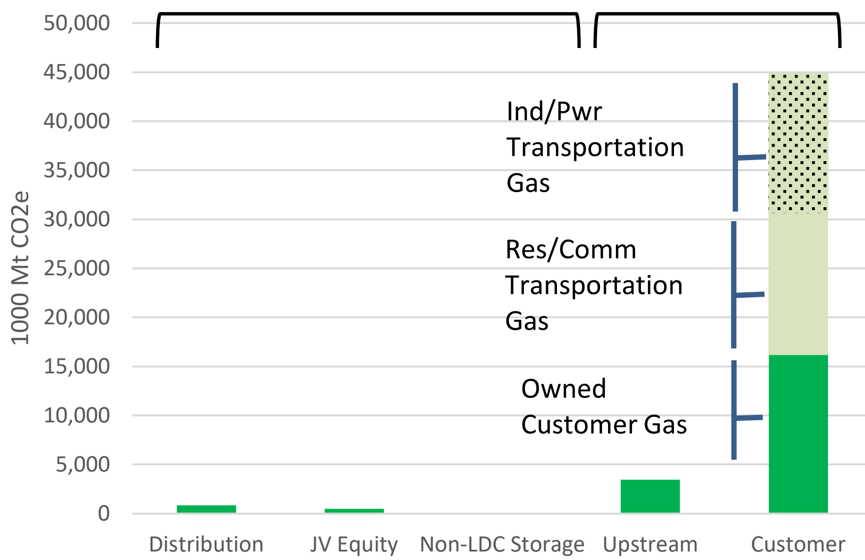
Figure 5 - Direct GHG Emissions by Company - 2019 (1000 Mt CO_2e)



In addition to the direct emissions, there were also indirect emissions, including the following primarily energy-related sources:

- Emissions from power plants that supply electricity used by the LDCs.
- Upstream emissions from the production, processing, and transportation of gas that is owned and sold by the LDCs.
- Emissions from customer use of gas delivered by the GAS LDCs.

Figure 6 - GAS Direct and Indirect Emissions - 2019 (1000 Mt CO_2e)



The emissions from customer use of gas are much larger than the direct emissions and follow the same proportions of sales vs transportation as the deliveries. The upstream emissions shown here include only the emissions associated with gas owned and sold by GAS as GAS does not know or control the source of gas purchased directly by customers.

2.3 Comparison to State Inventory

These states do not have comprehensive state GHG inventories to which to compare these emissions. However, ICF has assembled estimated state inventories from several sources:

- The U.S. Energy Information Administration (EIA) provides data on fossil fuel consumption by state that can be used to calculate the associated CO_2 emissions.
- The U.S. EPA Greenhouse Gas Reporting Program (GHGRP) reports GHG emissions including non-combustion GHG emissions from large industrial emitters. This is not a comprehensive inventory of these sources but likely captures most of the emissions.
- The EPA State Inventory Tool (SIT) is a tool that assists states in compiling their GHG inventories. The most recent data and assumptions in the agriculture module are for 2018, which was used to estimate that sector for this analysis.

Table 2 summarizes these estimates of state GHG emissions.

Table 2 - Estimated State GHG Emissions – 2019 (MMt CO_2e)

Source	MMt CO_2e				Data Source
	IL	GA	VA	TN	
Combustion					
Residential	25.0	7.4	6.2	5.4	EIA
Commercial	15.1	5.0	6.1	5.2	EIA
Industrial	26.4	13.9	11.4	12.5	EIA
Transportation	76.3	66.0	51.4	49.8	EIA
Power Gen	62.6	47.8	26.3	24.1	EIA
Combustion Subtotal	205.5	140.1	101.4	97.0	
Non-Combustion					

Methane - Landfills	2.6	5.6	2.9	2.7	GHGRP
Methane - Coal Mines	2.2	0.0	2.7	0	GHGRP
Methane - Gas Systems	0.6	0.2	0.3	0.3	GHGRP
Methane - Other	0.5	0.0	0.1	0.2	GHGRP
Other Non-CO_2	1.9	0.4	0.3	0.3	GHGRP
Non-Combustion CO_2	8.9	4.2	2.4	5.1	GHGRP
Manure Management	2.3	2.7	2.6	3.1	EPA SIT
Enteric Fermentation	2.2	4.6	0.8	0.4	EPA SIT
Soil Management	16.9	2.0	2.7	4.7	EPA SIT
Other Ag	0.6	0.0	0.2	0.2	EPA SIT
Non-Combustion Subtotal	38.7	19.9	15.0	17.0	
Total	244.1	159.9	116.4	114.1	

Comparing these results (in MMt) with the LDC data (in thousand Mt), the company emissions in 2019 had the characteristics summarized in Table 3.

Table 3 – LDC Emissions Comparison to State Inventories

	Nicor Gas	Atlanta Gas Light	VNG	CGC
Direct Emissions Percent of Total State GHG	<0.2%	0.2%	<0.1%	<0.1%
Methane Emissions Percent of State CH_4	5%	2%	<1%	0.1%
Total Company Direct and Indirect Emissions Percent of State GHG (Owned Gas)	7%	0.2%	1%	0.4%

2.4 Roadmap

The remainder of this report discusses ways that GAS can reduce both its direct and indirect GHG emissions. Section 3 discusses supply and cost of RNG. Section 4 addresses mitigation of direct emissions of methane and CO_2. Section 5 addresses mitigation of indirect emissions from customer use of gas, GAS use of electricity, and upstream emissions from production, processing, and transportation of gas. Section 6 discusses mitigation of GHG sources outside of GAS' direct operations. Section 7 summarizes the GHG reduction pathways identified in this report. Section 8 discusses policy and regulatory issues relevant to these pathways. Section 9 presents conclusions from the report. Chapters 10 through 13 present information specific to the individual companies.

3 Renewable Natural Gas

3.1 Overview

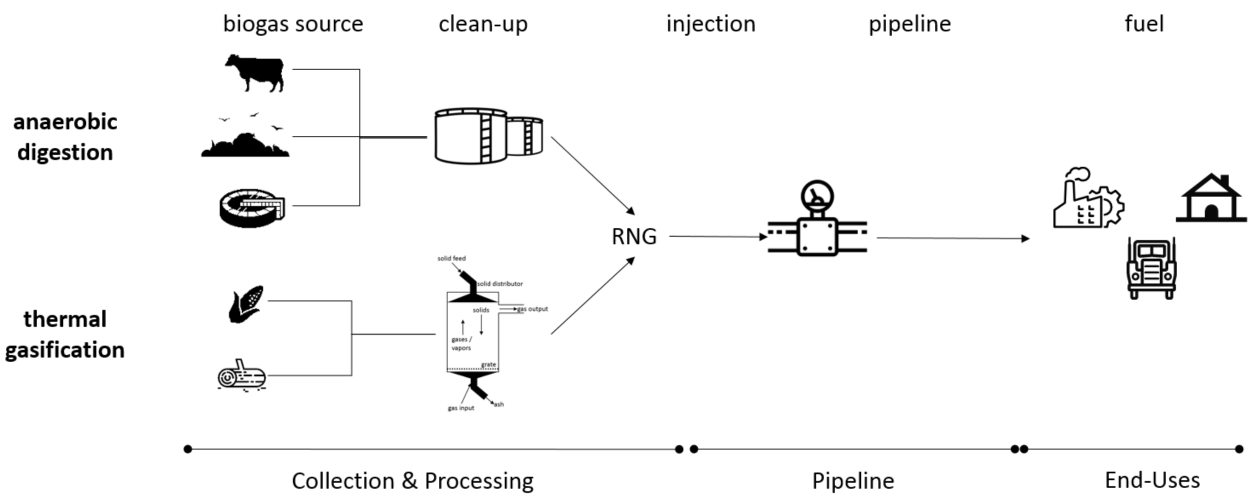
RNG is derived from biomass or other renewable resources and is pipeline-quality gas that is fully interchangeable with conventional natural gas. As a point of reference, the American Gas Association (AGA) uses the following definition for RNG:[8]

> *Pipeline-compatible gaseous fuel derived from biogenic or other renewable sources that has lower life cycle carbon dioxide equivalent (CO_2e) emissions than geological natural gas.* [9]

On a combustion bases, RNG is typically considered to be a biogenic, CO_2-neutral fuel. That is, the CO_2 released from combustion is CO_2 that was previously absorbed by plants from the atmosphere and there is therefore no net increase in atmospheric CO_2.[10]

RNG is produced over a series of steps (see Figure 7): collection of a feedstock, delivery to a processing facility for biomass-to-gas conversion, gas conditioning, compression, and injection into the pipeline. In this project ICF considers three RNG production technologies: anaerobic digestion and thermal gasification and RNG production from hydrogen.

Figure 7 - RNG Production Process via Anaerobic Digestion and Thermal Gasification



RNG can be produced from a variety of renewable feedstocks, as described in the table below.

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[8] AGA, 2019. RNG: Opportunity for Innovation at Natural Gas Utilities, https://pubs.naruc.org/pub/73453B6B-A25A-6AC4-BDFC-C709B202C819

[9] This is a useful definition but excludes RNG produced from the thermal gasification of the non-biogenic fraction of municipal solid waste (MSW). In most cases, however, the thermal gasification of the non-biogenic fraction of MSW yields lower CO_2e emissions than geological natural gas. As a result, MSW is included as an RNG resource in this study.

[10] For example, biogenic CO_2 emissions are not reported as a GHG in the EPA Inventory of GHG Emissions, the EPA GHGRP, corporate GHG reporting protocols, or GHG cap and trade programs.

Table 4 - RNG Feedstock Types

Feedstock for RNG		Description
Anaerobic Digestion	Animal manure	Manure produced by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses.
	Food waste	Commercial, industrial and institutional food waste, including from food processors, grocery stores, cafeterias, and restaurants.
	Landfill gas (LFG)	The anaerobic digestion of organic waste in landfills produces a mix of gases, including methane (40–60%).
	Water resource recovery facilities (WRRF)	Wastewater consists of waste liquids and solids from household, commercial, and industrial water use; in the processing of wastewater, a sludge is produced, which serves as the feedstock for RNG.
Thermal Gasification	Agricultural residue	The material left in the field, orchard, vineyard, or other agricultural setting after a crop has been harvested. Inclusive of unusable portion of crop, stalks, stems, leaves, branches, and seed pods.
	Energy crops	Inclusive of perennial grasses, trees, and annual crops that can be grown to supply large volumes of uniform and consistent feedstocks for energy production.
	Forestry and forest product residue	Biomass generated from logging, forest and fire management activities, and milling. Inclusive of logging residues, forest thinnings, and mill residues. Also materials from public forestlands, but not specially designated forests (e.g., roadless areas, national parks, wilderness areas).
	Municipal solid waste (MSW)	Refers to the non-biogenic fraction of waste that would be landfilled after diversion of other waste products (e.g., food waste or other organics), including construction and demolition debris, plastics, etc.

In addition to providing a CO_2-neutral fuel, RNG development provides environmental benefits by converting animal, food, and agricultural waste into a useful fuel and avoiding the release of these wastes and associated byproducts into the environment. Notably it avoids the release of methane directly into the environment as a GHG. A recent study found that animal manure and food waste are significant contributors to PM 2.5 emissions that have major public health impacts.[11] RNG projects reduce these emissions while generating a useful CO_2-neutral fuel. These projects can benefit agriculture interests and food processors by converting a complex and costly waste disposal requirement into a clean, revenue-producing process. RNG development also creates construction and operation jobs and secondary economic benefits.

3.1.1 Anaerobic Digestion

The most common way to produce RNG today is via anaerobic digestion, whereby microorganisms break down organic material in an environment without oxygen. The four key processes in anaerobic digestion are:

- Hydrolysis
- Acidogenesis
- Acetogenesis

[11] “Air quality–related health damages of food”, Nina G. G. Domingo, et al, PNAS May 18, 2021 118 (20) e2013637118; https://doi.org/10.1073/pnas.2013637118

- Methanogenesis

Hydrolysis is the process whereby longer-chain organic polymers are broken down into shorter-chain molecules like sugars, amino acids, and fatty acids that are available to other bacteria. Acidogenesis is the biological fermentation of the remaining components by bacteria, yielding volatile fatty acids, ammonia, carbon dioxide, hydrogen sulfide, and other byproducts. Acetogenesis of the remaining simple molecules yields acetic acid, carbon dioxide, and hydrogen. Lastly, methanogens use the intermediate products from hydrolysis, acidogenesis, and acetogenesis to produce methane, carbon dioxide, and water, where the majority of the biogas is emitted from anaerobic digestion systems.

The process for RNG production generally takes place in a controlled environment, referred to as a digester or reactor, including landfill gas facilities. When organic waste, biosolids, or livestock manure is introduced to the digester, the material is broken down over time (e.g., days) by microorganisms, and the gaseous products of that process contain a large fraction of methane and carbon dioxide. The biogas requires capture and then subsequent conditioning and upgrade before pipeline injection. The conditioning and upgrading helps to remove any contaminants and other trace constituents, including siloxanes, sulfides, and nitrogen, that cannot be injected into common carrier pipelines, and increases the heating value of the gas for injection.

3.1.2 Thermal Gasification

Biomass-like agricultural residues, forestry and forest produce residues, and energy crops have high energy content and are ideal candidates for thermal gasification. The thermal gasification of biomass to produce RNG occurs over a series of steps:

- Feedstock pre-processing in preparation for thermal gasification (not in all cases).
- Gasification, which generates synthetic gas (syngas), consisting of hydrogen and carbon monoxide (CO).
- Filtration and purification, where the syngas is further upgraded by filtration to remove remaining excess dust generated during gasification, and other purification processes to remove potential contaminants like hydrogen sulfide and carbon dioxide.
- Methanation, where the upgraded syngas is converted to methane and dried prior to pipeline injection.

Biomass gasification technology is at an early stage of commercialization, with the gasification and purification steps challenging. Prior to recent advancements, the gasification process yielded a residual tar, which can foul downstream equipment. Furthermore, the presence of tar effectively precludes the use of a commercialized methanation unit. The high cost of conditioning the syngas in the presence of these tars has limited the potential for thermal gasification of biomass. For instance, a 1998, study[12] concluded that after "two decades" of experience in biomass gasification, "'tars' can be considered the Achilles heel of biomass gasification."

[12] NREL, Biomass Gasifier "Tars": Their Nature, Formation, and Conversion, November 1998, NREL/TP-570-25357. Available online at https://www.nrel.gov/docs/fy99osti/25357.pdf.

Over the last several years, however, a few commercialized technologies have been deployed to increase syngas quantity and prevent the fouling of other equipment by removing the residual tar before methanation. There are a handful of technology providers in this space, including Haldor Topsoe's tar-reforming catalyst. Frontline Bioenergy takes a slightly different approach and has patented a process producing tar-free syngas (referred to as TarFreeGas™).

In general, ICF considers the challenges facing thermal gasification technology as surmountable, particularly in the medium-term and beyond. In the context of long-term decarbonization and related climate policy objectives, the commercialization of thermal gasification does not require significant technological breakthroughs, in contrast to other mitigation measures, such as carbon capture and storage, or fuel cells.

For example, a handful of thermal gasification projects are in the late stages of planning and development in North America. REN is proposing to build a modular thermal gasification facility in British Columbia using wood waste to produce pipeline-quality RNG for the local natural gas utility, FortisBC.[13] Sierra Energy's thermal gasification and biorefinery facility in Nevada produces RNG and liquid fuels using municipal solid waste as a feedstock.[14] West Biofuels has a number of demonstration and research projects using biomass to produce RNG, as well as commercialized thermal gasification facilities producing other renewable fuels.[15] Further afield there are demonstration and early-commercialization thermal gasification projects across Europe, including Sweden, France and Austria.[16] With the development of a supportive policy and regulatory framework, interest in thermal gasification projects has the potential to escalate over time.

Biomass, particularly agricultural residues, is often added to anaerobic digesters to increase gas production (by improving carbon-to-nitrogen ratios, especially in animal manure digesters). It is conceivable that some of the feedstocks considered here could be used in anaerobic digesters. For simplicity, ICF did not consider any multi-feedstock applications in our assessment; however, it is important to recognize that the RNG production market will continue to include mixed feedstock processing in a manner that is cost-effective.

3.1.3 Hydrogen and Power-to-Gas/Methanation

Renewable electricity can be used to split water into hydrogen and oxygen, and the hydrogen can be used directly or further processed to produce methane. If the electricity is sourced from renewable resources, such as wind and solar, then the resulting fuels are carbon-neutral. This is especially cost-effective when wind or solar generation exceeds demand and would otherwise be curtailed by the power grid.

The key step in this process is the production of hydrogen from renewably generated electricity by means of electrolysis. This hydrogen conversion method is not new, and there are three

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[13] FortisBC, 2020. Filing of a Biomethane Purchase Agreement between FEI and REN Energy International Corp, https://www.bcuc.com/Documents/Proceedings/2020/DOC_57461_B-1-FEI-REN-Sec-71-BPA-Application-Confidential-Redacted.pdf.
[14] Sierra Energy, 2020. https://sierraenergy.com/projects/fort-hunter-liggett/
[15] West Biofuels, 2020. http://www.westbiofuels.com/projects?filter=research
[16] Thunman, H. et al, 2018. Advanced biofuel production via gasification - lessons learned from 200 years man-years of research activity with Chalmers' research gasifier and the GoBiGas demonstration plant. Energy Science & Engineering, 29.

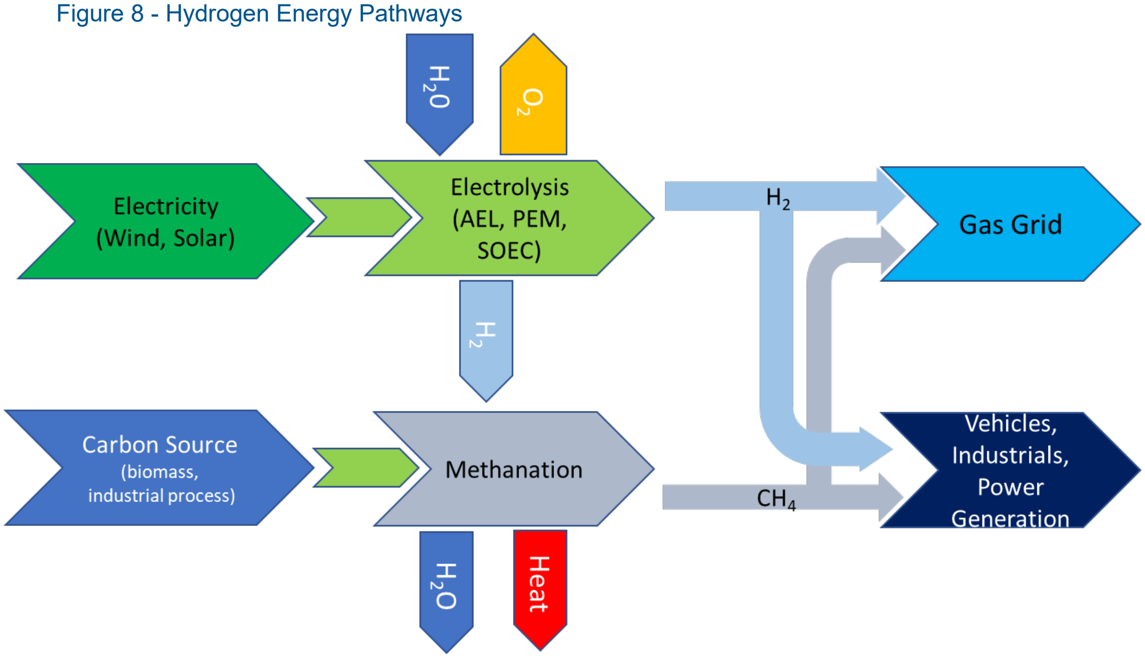
electrolysis technologies with different efficiencies and in different stages of development and implementation:

- Alkaline electrolysis, where two electrodes operate in a liquid alkaline solution,
- Proton exchange membrane electrolysis, where a solid membrane conducts protons and separates gases in a fuel cell, and
- Solid oxide electrolysis, a fuel cell that uses a solid oxide at high temperatures.

The hydrogen produced in this way is a highly flexible energy product that can be:

- Stored as hydrogen and used to generate electricity at a later time using fuel cells or conventional generating technologies – in effect functioning as energy storage with extended capacity, timing, and duration greater than existing electric batteries,
- Injected as hydrogen into the natural gas infrastructure, where it augments the natural gas supply, or
- Converted to methane and injected into the natural gas system.

Figure 8 - Hydrogen Energy Pathways



Hydrogen can potentially be mixed directly with natural gas in pipeline systems, up to certain blending proportions, and used in place of natural gas in some applications. Hydrogen combustion does not produce any CO_2 so it is a GHG-neutral fuel at the point of use. However, hydrogen has different combustion characteristics from methane and different operational characteristics in the distribution network that limit its direct use. That said, in certain locations hydrogen has been blended with natural gas or RNG up to 15 to 20% by volume without affecting distribution or end use operations. This is equivalent to about 5 to 7% by energy content due to hydrogen's lower energy density. Hydrogen blending is being demonstrated at distribution companies in Europe[17] and some locations in the U.S. (for example Hawaii Gas[18]) and is a potential future resource for GAS.

Pure hydrogen could be used as GHG-neutral fuel for specific locations with dedicated hydrogen production or delivery infrastructure and end use equipment. For example, a large industrial facility or group of facilities could form a “hydrogen island” to produce hydrogen on-site and use it in combustion equipment designed to use hydrogen. Renewable hydrogen could also be used to produce industrial feedstocks such as ammonia.

The last but possibly most immediate option, methanation, involves combining hydrogen with CO_2 (from non-fossil sources) to produce methane. The methane produced is known as Power to Gas (P2G) and for the purposes of this study is included in the RNG supply analysis. It is a clean alternative to conventional fossil natural gas, as it can directly displace fossil natural gas for combustion in buildings, vehicles, and electricity generation without releasing incremental CO_2 emissions. Methanation avoids the cost and inefficiency associated with hydrogen storage and creates more flexibility in the end use through the natural gas system. The P2G-RNG conversion process can also be coordinated with conventional biomass-based RNG production by using the surplus CO_2 in biogas to produce the methane, creating a productive use for the CO_2.

A critical advantage of P2G is that the RNG produced is a highly flexible and interchangeable carbon neutral fuel. With a storage and infrastructure system already established, RNG from P2G can be produced and stored over the long term, allowing for deployment during peak demand periods in the energy system. RNG from P2G also utilizes the highly reliable and efficient existing natural gas transmission and distribution infrastructure, the upfront costs of which have already been incurred.

Southern Company is actively participating in research and development activities for the production and use of hydrogen, and the potential for hydrogen blending, that could be applied in multiple applications in the future.

3.2 RNG Inventory for GAS

ICF has developed an RNG inventory and projection for the GAS service territories and surrounding states. While this resource assessment applies the biomass feedstock categories as a framework to assess RNG potential, these categories are not necessarily discrete and RNG production facilities can utilize multiple feedstock and waste streams. For example, food waste is often added to anaerobic digester systems at WRRFs to augment biomass and overall gas production. In addition, current waste streams can potentially be diverted from one feedstock category to another, such as MSW or food waste that is currently landfilled being diverted away from landfills and LFG facilities.

To avoid the potential double counting of biomass, LFG potential is derived from current waste-in-place estimates and does not include any projections of waste accumulation or the

[17] “Technical and economic conditions for injecting hydrogen into natural gas networks”, June 2019, https://www.grtgaz.com/fileadmin/plaquettes/en/2019/Technical-economic-conditions-for-injecting-hydrogen-into-natural-gas-networks-report2019.pdf
[18] https://www.hawaiigas.com/clean-energy/hydrogen/

introduction of waste diversion. This likely underestimates the potential of RNG from LFG, but additional biomass that could potentially be used to produce RNG is captured in other feedstock categories, such as MSW and food waste.

ICF used a mix of existing studies, government data, and industry resources to estimate the current and future supply of the feedstocks. Table 5 summarizes some of the resources that ICF drew from to complete our resource assessment, broken down by RNG feedstock.

This RNG feedstock inventory does not take into account resource availability—in a competitive market, resource availability is a function of factors including but not limited to: demand, feedstock costs, technological development, and the policies in place that might support RNG project development. ICF assessed the RNG resource potential of the different feedstocks that could be realized given the necessary market considerations.

Table 5 - List of Data Sources for RNG Feedstock Inventory

Feedstock for RNG	Potential Resources for Assessment
Animal manure	▪ U.S. Environmental Protection Agency (EPA) AgStar Project Database ▪ U.S. Department of Agriculture (USDA) Census of Agriculture
Food waste	▪ U.S. Department of Energy (DOE) 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework (KDF)
LFG	▪ U.S. EPA Landfill Methane Outreach Program ▪ Environmental Research & Education Foundation (EREF)
WRRFs	▪ U.S. EPA Clean Watersheds Needs Survey (CWNS) ▪ Water Environment Federation
Agricultural residue	▪ U.S. DOE 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework
Energy crops	▪ U.S. DOE 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework
Forestry and forest product residue	▪ U.S. DOE 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework
MSW	▪ U.S. DOE 2016 Billion Ton Report ▪ Waste Business Journal

Table 6 summarizes the maximum RNG potential for each biomass-based feedstock and production technology for GAS company service territories and the rest of each state, reported in million cubic feet (MMcf). The RNG potential includes different variables for each feedstock, but ultimately reflects the most favorable options available, such as the highest biomass price and the utilization of all feedstocks at all facilities.

The estimates included in this table are based on the maximum RNG production potential from all feedstocks, and do not apply any economic or technical constraints on feedstock availability.

An assessment of resource availability is addressed in Section 3.3, which also includes a comparison of these volumes to deliveries of conventional gas.

Table 6 - Technical Potential for GAS RNG Production by Feedstock (MMcf/yr)

RNG Feedstock	GAS	Rest of States	Total
Animal Manure	47,924	111,246	159,171
Food Waste	6,126	4,987	11,112
Landfill Gas	83,723	61,751	145,474
Water Resource Recovery Facilities	6,978	4,062	11,040
Anaerobic Digestion Sub-Total	144,751	182,046	326,797
Agricultural Residue	161,043	159,773	320,817
Energy Crops	341,104	828,497	1,169,601
Forestry & Forest Product Residue	20,416	45,851	66,267
Municipal Solid Waste	54,005	43,994	98,000
Thermal Gasification Sub-Total	576,569	1,078,116	1,654,685
Total	721,320	1,260,162	1,981,482

3.3 Supply Curves

ICF developed economic supply curves for three separate scenarios for each feedstock. The RNG potential included in the supply curves is based on an assessment of resource availability. In a competitive market, that resource availability is a function of multiple factors, including but not limited to demand, feedstock costs, technological development, accessibility to pipeline connections, and the policies in place that might support RNG project development. ICF assessed the RNG resource potential of the different feedstocks that could be realized, given the necessary market considerations (without explicitly defining what those are).

ICF applied a logistic function to model the growth potential of the RNG production, whereby the initial stage of growth is approximated as an exponential, and thereafter growth slows to a linear rate and then approaches a plateau (or limited to no growth) at maturity.

3.3.1 Scenarios

ICF developed three scenarios for each feedstock—with variations among limited, moderate, and higher utilization assumptions regarding utilization of the feedstock, summarized below.

- **Limited Adoption** represents a low level of feedstock utilization, with utilization levels depending on feedstock, with a range from 25% to 50% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rate of feedstocks for thermal gasification in this scenario is 30%, at lower biomass prices. Overall, the Limited Adoption scenario captures 9% of the potential RNG feedstock resource based on the inventory.
- **Moderate Deployment** represents balanced assumptions regarding feedstock utilization, with a range from 40% to 75% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rates of feedstocks for thermal gasification in this scenario ranges from 40% to 50% at medium biomass prices. The Moderate Deployment scenario captures 26% of the potential RNG feedstock resource available.

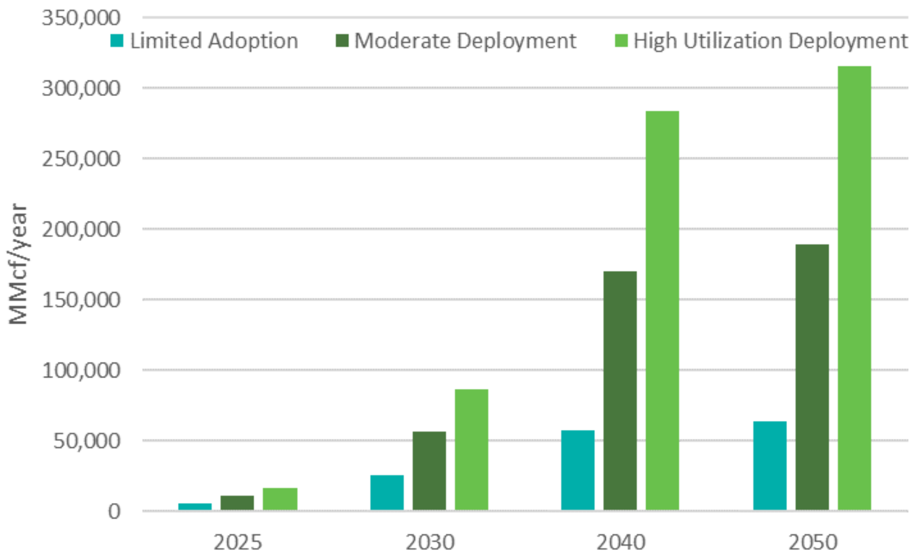
- **High Utilization Deployment** represents higher levels of utilization, with a range from 50% to 90% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rate of feedstocks for thermal gasification in this scenario ranges from 50% to 70% at medium-to-high biomass prices. The High Utilization Deployment scenario captures 44% of the potential RNG feedstock resource available and does not represent a maximum achievable or technical potential scenario.

ICF projected the potential for RNG for pipeline injection, broken down by the feedstocks presented previously and considering the potential for RNG growth over time, with 2050 being the final year in the analysis. The projections include the Limited Adoption, Moderate Deployment, and High Utilization Deployment RNG production scenarios, varying both the assumed utilization of existing resources as well as the rate of project development required to deploy RNG at the volumes presented. The RNG resource potential scenarios demonstrate that both near-term and long-term deployment of RNG can help decarbonize the natural gas system, ranging from over 64,000 MMcf in the Limited Adoption scenario to almost 316,000 MMcf in the High Utilization Deployment scenario in the GAS service territories in 2050, with more supply available in other parts of the state. This RNG potential is spread across the eight feedstocks and two production technologies, demonstrating the local diversity of RNG resources and avoided reliance on a particular source of RNG over the long-term.

Table 7 - Projected Annual RNG Production in GAS Service Territories by 2050 (MMcf/yr)

RNG Feedstock		Scenario		
		Limited Adoption	Moderate Deployment	High Utilization Deployment
Anaerobic Digestion	Animal Manure	7,217	13,830	19,925
	Food Waste	2,514	3,643	4,454
	LFG	14,303	26,743	39,066
	WRRFs	2,930	4,617	6,036
Thermal Gasification	Agricultural Residue	4,338	62,412	76,262
	Energy Crops	13,140	47,663	128,744
	Forestry and Forest Product Residue	6,125	10,208	14,291
	Municipal Solid Waste	13,896	20,729	27,003
Total		64,462	189,845	315,782

Figure 9 - Growth Scenarios for Annual RNG Production in GAS Service Territories (MMcf/yr)



The primary determinant of P2G supply is the availability of renewable electricity for electrolysis, ranging from curtailed renewable generation only to generation that is dedicated to hydrogen/P2G production. For this analysis, ICF used its Integrated Planning Model (IPM®) power sector modeling platform to develop a supply-cost curve for renewable electricity from 2025 to 2050. IPM provides an integrated model of wholesale power, system reliability, environmental constraints, fuel choice, transmission, capacity expansion, and all key operational elements of generators on the power grid in a linear optimization framework. ICF applied the IPM forecasts of renewable electricity generation to develop the following three scenarios for production of RNG from P2G:

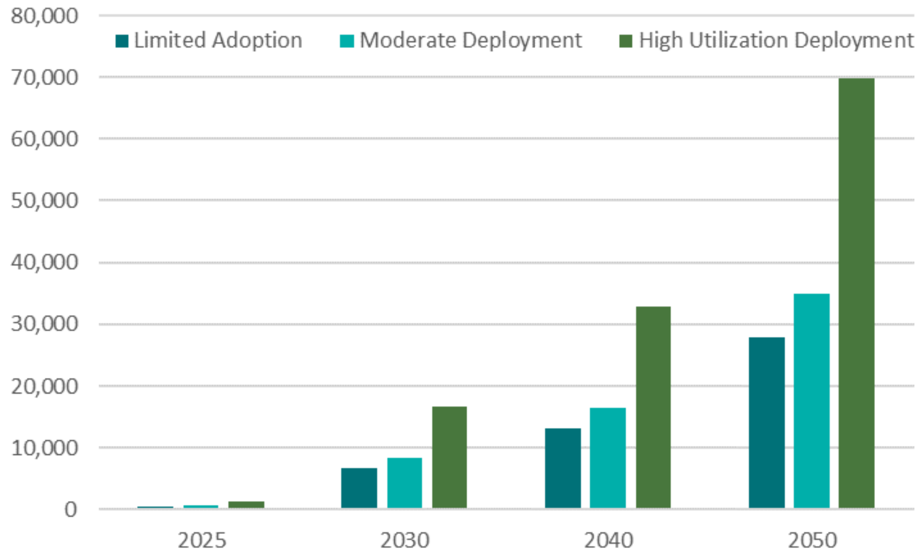
- In the Limited Adoption scenario, ICF assumed that an additional 10% of the renewable generation at each time step would need to be curtailed and available for P2G production. This is a simplification of curtailment, particularly over the long-term as more stringent Renewable Portfolio Standard or Clean Energy Standard policies are implemented.
- In the Moderate Deployment scenario, ICF assumed that additional renewable electricity generation is built dedicated to hydrogen and P2G production, with an additional 25% of the renewable generation available at each time step for P2G production.
- In the High Utilization Deployment scenario, ICF assumed that additional renewable electricity generation is dedicated to hydrogen and P2G production, with an additional 50% of the renewable generation available at each time step for P2G production.

These assumptions reflect an over-simplification of electricity markets, the interlinkages between the electric and gas sectors, and increasing emergence of issues such as curtailment as electric grids deeply decarbonize over the long-term. The P2G estimates outlined here are illustrative and intended to provide an indication of P2G production potential under a set of simplified parameters, rather than a comprehensive forecast or projection of P2G production. The P2G potential is summarized in Table 8 and Figure 10 and ranges from 27,900 to 69,850 MMcf per year of P2G by 2050.

Table 8 – 2050 GAS P2G Potential (MMCF)

Nicor Gas	Atlanta Gas Light	VNG	CGC
10,600 to 26,600	14,600 to 36,500	2,600 to 6,500	100 to 250

Figure 10 - P2G Production Scenarios for GAS (MMcf/yr)



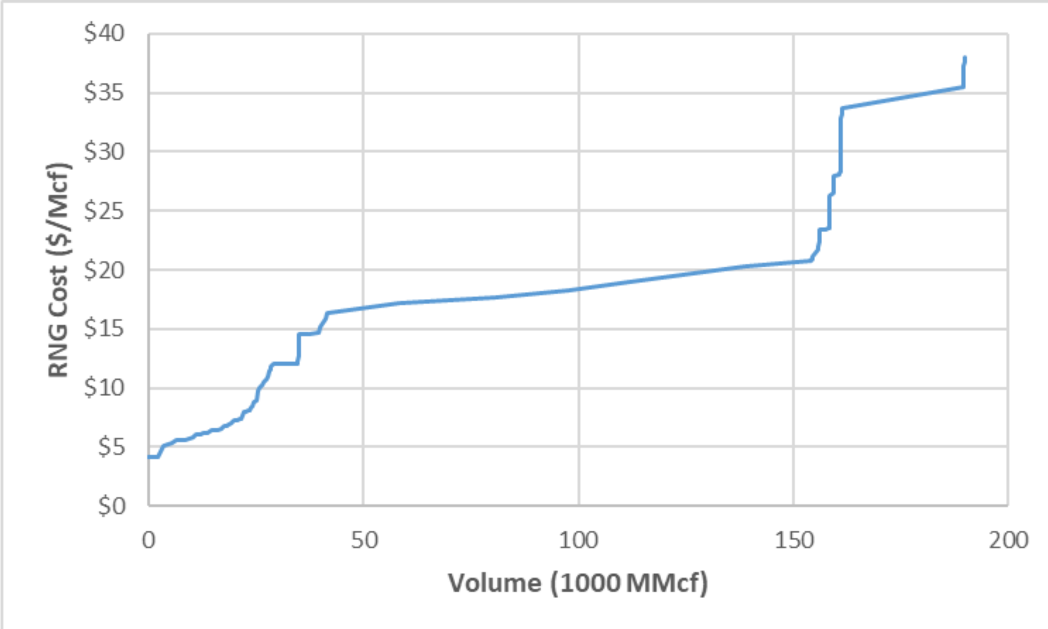
3.4 Supply-Cost Curve for RNG

Figure 11 shows an estimated supply-cost curve for RNG in 2050, including resource potential (along the x-axis) and the estimated cost to deliver that RNG (along the y-axis). The supply-cost curves do not necessarily reflect the price for RNG available on the market today, but instead the estimated production costs for RNG as deployment increases over time. Regulatory-driven supply scarcity related to low-carbon transportation fuel has resulted in higher costs in some regions at some times. Direct utility development of RNG projects can avoid these market disruptions and provide RNG closer to production cost levels. Supply curves reflect the supply scenario, the location, and the year.

In 2050, the front end of the supply curve is comprised of large landfill gas facilities, WRRFs and animal manure projects. Thermal gasification systems are expected to be cost competitive in the 2040 to 2050 timeline and deliver large volumes of RNG around the $20/MMBtu range. In 2050, the back end of the supply curve is driven by higher costs of anaerobic digestion at smaller farms, WRRFs and thermal gasification facilities. Overall, the estimated average weighted production cost for the Achievable Deployment scenario is $19.80/MMBtu. Due to the different geographies, the supply curve excludes P2G supply, although as noted above P2G weighted average production costs are estimated to be around $20/MMBtu to $25/MMBtu.

Although the RNG price is higher than the commodity price of natural gas, it has increased value as a CO_2-neutral fuel. The measure of this value is in the analysis of the cost of GHG reduction as compared to other GHG reduction options, as evaluated in Section 5.1.

Figure 11 – Example Supply-Cost Curve - 2050 ($/MMBtu)



3.5 Methane Capture Offsets

One other aspect of RNG development is the creation of methane capture offsets. In some cases, RNG projects capture methane that would otherwise be released to the atmosphere. Because methane is itself a GHG, avoiding these emissions results in a GHG reduction. These reductions can be turned into creditable and transferrable emission offsets according to strict protocols. The reductions must be below the emissions that would otherwise have occurred and in addition to reductions already occurring or required by regulation and must be carefully and transparently measured and verified. Offsets of this kind are widely accepted in emission cap and trade programs such as the California, RGGI, and European Union cap and trade programs.

Once a project has been identified, the developer identifies an appropriate offset creation protocol from one of the certification organizations such as the U.N. Clean Development Mechanism, the Climate Action Reserve, the American Carbon Registry, or other similar organizations. These protocols ensure that the offsets are based on real and verifiable reductions that would not have otherwise been achieved. The developer submits the required analysis and data on the project to a third-party auditor for verification. The analysis can also be submitted to one of the certification organizations. If the project meets the relevant criteria, the developer can periodically submit the data to quantify and be awarded creditable offsets. The original certification would ensure that the reductions meet the qualitative criteria and establish the parameters for ongoing quantification. In the RNG case, the primary quantification factor would be the amount of methane produced and captured versus the emissions that would have otherwise occurred. The creditable offsets will be discounted somewhat to account for losses and emissions associated with capturing and processing the methane.

The most likely source for methane capture offsets in the GAS service territories would be from dairy and swine operations, however others may exist. Table 9 summarizes the range of potentially available methane capture offsets for each company service territory by 2050. There is additional potential outside the service territories.

Table 9 – 2050 Methane Capture Offset Potential (1000 Mt CO_2e)

Nicor Gas	Atlanta Gas Light	VNG	CGC
750 to 1,726	94 to 328	2.4	70

The RNG potential can be compared to current and future gas deliveries for each company. This information is presented in the individual company chapters.

3.6 GHG Cost-Effectiveness

The GHG cost-effectiveness is reported on a dollar-per-ton basis and is calculated as the difference between the emissions attributable to RNG and fossil natural gas. For this report, ICF followed IPCC guidelines and does not include biogenic emissions of CO_2 from RNG. The cost-effectiveness calculation is:

$$\Delta(RNG_{cost}, Fossil\ NG_{cost}) \Big/ 0.05306\ MT\ CO_{2e}$$

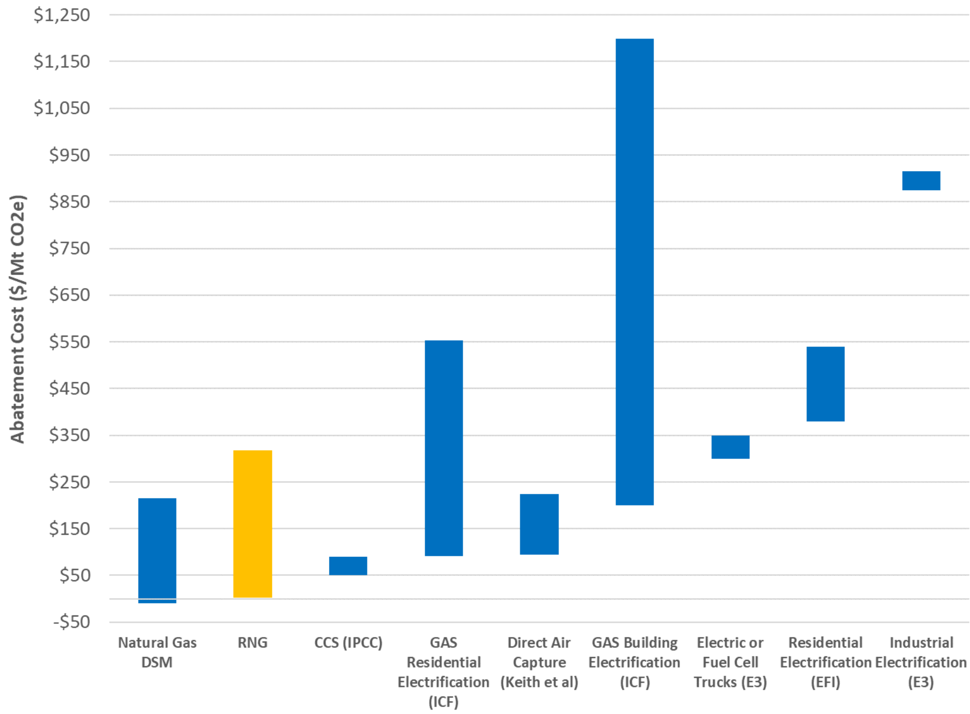
where the RNG_{cost} is the cost from the estimates reported previously. The fossil natural gas price is the range of the utility citygate prices reported by the EIA for years 2015 to 2019,[19] ranging from \$3.18/MMBtu to \$4.87/MMBtu. The front end of the supply-cost curve is showing RNG of less than \$5/MMBtu, which is equivalent to about \$2.45/Mt CO_2e. As the estimated RNG cost increases to \$20/MMBtu, the estimated cost-effectiveness approaches \$320/Mt CO_2e.

Estimating the cost-effectiveness of different GHG emission reduction measures is challenging and results can vary significantly across temporal and geographic considerations. Figure 12 shows an example comparison for GAS of selected measures across various key studies for specific abatement measures that are likely to be required for economy-wide decarbonization in the 2050 timeframe, including natural gas demand side management (DSM),[20] RNG (from this study), carbon capture and storage (CCS),[21] direct air capture (whereby CO_2 is captured directly from the air and a concentrated stream is sequestered or used for beneficial purposes),[22] battery electric trucks (including fuel cell drivetrains),[23] and policy-driven electrification of certain

[19] EIA, Natural Gas Data, https://www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_PG1_DMcf_a.htm
[20] See Con Edison's Smart Usage Rewards program (https://www.coned.com/en/save-money/rebates-incentives-tax-credits/smart-usage-rewards-for-reducing-gas-demand) and National Grid's Demand Response Pilot program (https://www.nationalgridus.com/GDR).
[21] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.).
[22] Keith, DW; Holmes, G; St Angelo D; Heidel, K; A Process for Capturing CO_2 from the Atmosphere, *Joule*, 2 (8), p1573-1594. https://doi.org/10.1016/j.joule.2018.05.006
[23] E3, 2018. Deep Decarbonization in a High Renewables Future, https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization

end uses (including buildings and in the industrial sectors).[24, 25] For policy-driven building electrification, abatement costs include appliance and equipment costs, installation costs, maintenance costs, fuel costs (including the assumed cost of electricity) and conversion or retrofit costs. The exact composition of building electrification abatement costs can vary substantially across climate and building type, among other variables. Similar charts are found in the chapter for each company.

Figure 12 - GHG Abatement Costs, Selected Measures ($/Mt CO_2e)



[24] Energy Futures Initiative (EFI), 2019. Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California, https://energyfuturesinitiative.org/efi-reports.
[25] ICF- Scenario 3 in this report.

4 Mitigation of Direct Emissions

This section identifies potential pathways to reduce direct GHG emissions. These emissions include:

- Methane emissions (fugitive and vented) from LDC and storage operations.
- CO_2 emissions from combustion at the LDC, storage, and fleet operations.

4.1 Methane Emissions

Methane is the primary constituent of natural gas, typically comprising 93 to 95% by volume. Methane is a greenhouse gas with a warming potential greater than that of CO_2. The greater effect is measured by weighting the methane emissions by a Global Warming Potential (GWP). The GWP is a function of the time over which it is considered and is subject to periodic updating by the U.N. Intergovernmental Panel on Climate Change (IPCC). The U.S. EPA and individual states use a GWP of 25 for methane to calculate GHG inventories as specified by the U.N. Framework Convention on Climate Change (UNFCCC) and that factor is used in this analysis.

These emission estimates are based on U.S. EPA emission calculation methodologies from the National Inventory of Greenhouse Gas Emissions and Sinks[26] (GHGI) and the EPA Greenhouse Gas Reporting Rule (GHGRP).[27] Many of the applicable methodologies are based on fixed emission factors applied to a population count (per mile of pipe, per meter, etc.). This approach is reasonable for national or regional estimates, but it has limitations for company-specific estimates. It does not allow for more accurate data that may be available through direct emission measurements and it does not allow the recognition of measures that are taken to reduce emissions from these sources.

Based on the EPA methodologies, Figure 13 shows that three components accounted for 94% of the total GAS emissions. Customer meters comprised 28%, distribution mains and services comprised 49%, and dig-ins (damage to mains and services from construction) comprised 17%.

[26] Inventory of U.S. Greenhouse Gas Emissions and Sinks, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks
[27] Greenhouse Gas Reporting Program, https://www.epa.gov/ghgreporting

Figure 13 - GAS Methane Emissions by Source 2019 (Mt CH_4)

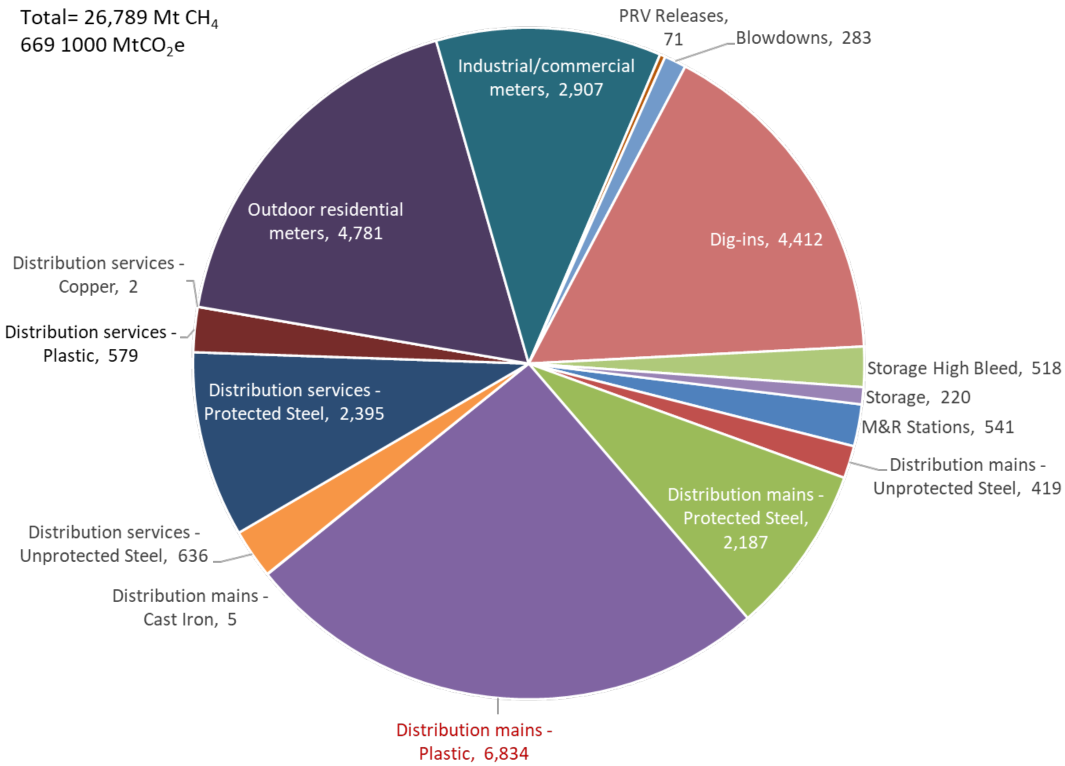
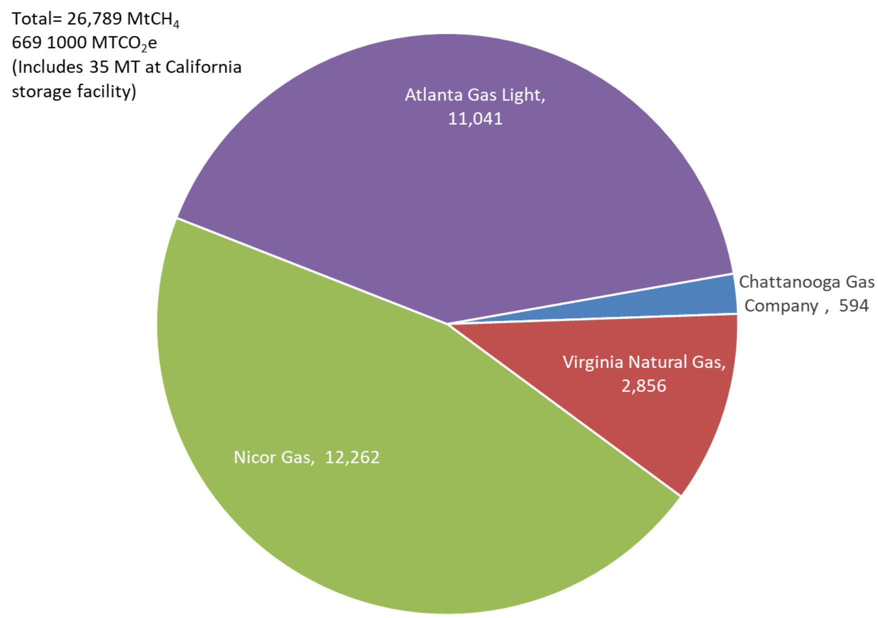


Figure 14 shows the methane emissions by company for 2019.

The potential pathways to reduce these emissions include:

- Measures to reduce emissions by replacing the components counted by the EPA methodologies (miles of higher-emitting pipeline).
- Measures to reduce emissions through other mitigation measures and more accurate measurement and reporting methodologies.

Figure 14 - GAS Methane Emissions by Company 2019 (Mt CH_4)



4.1.1 Customer Meters

The 2019 EPA emissions estimates for meters were based on per meter emission factors that come from studies performed in the 1990s. Using the EPA fixed per unit emission factor approach does not allow a pathway to demonstrate reduced emissions even if mitigation measures are implemented. U.S. EPA recently adopted new, significantly higher emission factors in the GHG inventory for commercial and industrial meters based on a recent NREL/GTI leak survey report.[28] The new factor for industrial meters is more than ten times the factor used for the 2019 inventory. Use of the new factors would increase the estimated emissions by over 5,700 Mt CH_4 or a 22% increase in overall methane emissions.

The NREL/GTI report found a very skewed distribution of leaks. That is, the vast majority of meters had no leaks or only very small leaks. A very small number had larger leaks that accounted for most of the emissions - 10% of the meters accounted for 80% of the emissions. ICF has seen similar data from surveys of residential meters from other gas companies. The available data indicates that leakage is mostly from “meter sets” (associated piping, manifolds, and connectors) rather than from the meter itself.

A potential mitigation approach would be to implement an expanded meter leak detection and repair (LDAR) program, which would provide a more accurate estimate of actual emissions including the impact of the LDAR, document actual emissions from meters (most will likely be zero or very low), and identify the small number with significant leaks, which could then be repaired.

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[28] NREL, “Classification of Methane Emissions from Industrial Meters, Vintage vs Modern Plastic Pipe, and Plastic-lined Steel and Cast-Iron Pipe”, June 30, 2019. DOE DE-FE0029061

Meters are already being surveyed for corrosion and integrity monitoring, which includes leak detection, measurement of atmospheric methane concentration (ppm), and flagging for repair where required. A new program would leverage the existing surveys to include actual volumetric measurements for identified leaks. This would allow for calculation/estimation of actual volumes from leaks and would allow for the development of a company-specific emission factor for meter sets. The program might require more frequent surveys and/or prioritizing larger commercial/ industrial meters for attention. The NREL/GTI industrial commercial study states that repairing the 10% highest emitting meters would reduce emissions by 72%. Data on residential meters from other companies shows a similar trend, with average emissions 80% lower than the EPA emission factor even before repairs. Based on these data points ICF projects that an expanded meter LDAR program could result in documented emissions 80% below the EPA estimates.

The basic leak detection and repair surveys are already being performed. The incremental cost would be to quantify and record the emissions prior to the repair and organize and analyze the data. The frequency of the surveys might be increased depending on the current baseline. A three-year cycle might be a reasonable basis. Assuming that the cost is only the cost to repair the identified leaks, the cost of emissions reductions could be less than \$1/Mt CO_2e, assuming four hours for each quantification/repair, three years application of the emission reduction, and leaker rates 50 to 100 times the EPA emission factor, as indicated in the surveys. Table 10 summarizes the baseline emissions, the potential emissions estimates with the revised EPA emission factors and the potential emissions estimates based on measurement and repair for customer meters at each company.

Table 10 - Meter Emissions and Potential Reduction Estimates (Mt CH_4)

	Nicor Gas	Atlanta Gas Light	VNG	CGC
Emissions w/Current Factor	4,230	2,719	566	172
Emissions w/Revised Factor	8,067	4,148	916	317
Potential Reduced Emissions	846	544	113	34

4.1.2 Mains and Service Lines

Emissions from gas mains and service lines are also based on per unit emissions factors (miles for mains, number of services for services) that are specific to the pipeline material. Cast-iron and unprotected steel pipes have much higher emission factors than protected steel or plastic. While some of the companies have already replaced most of the higher emitting pipe materials, there were still some unprotected steel and cast iron pipes remaining. GAS has been replacing these higher-emitting pipes through pipeline integrity and safety programs and estimates that it has reduced annual methane emissions from its distribution system from 1998 to 2018 by approximately 50% — even as the system grew by more than 20%. It is assumed that the remainder of the high-emitting pipe will be replaced under pipeline integrity and safety programs, resulting in emission reductions shown in Table 11. Atlanta Gas Light has already completed this process.

Table 11 – GAS Pipe Emissions Estimates (Mt CH_4)

	Nicor Gas	Atlanta Gas Light	VNG	CGC
2019 Emissions	4,796	6,034	1,918	311
Potential Emissions After Reductions	4,627	6,034	1,076	303

While these replacements are currently being paid for under pipeline integrity programs, Table 12 shows the cost of reduction if the costs were being treated as GHG reduction costs. (This calculation assumes replacement with plastic pipe, but replacement with protected steel would yield approximately the same results.)

Table 12 - Cost-Effectiveness of Pipeline Replacement

	$/Mt CO_2e Reduced
Cast Iron Main	$452
Unprotected Steel Main	$614
Unprotected Steel Service	$346

Assumptions:
All pipes replaced with plastic
60-year life for mains
40-year life for services
$3/Mcf of gas saved
$775,000 per mile of main replaced
$5,000 per service replaced

Direct measurement of pipeline emissions and development of company-specific emission factors for mains and services have not been demonstrated to-date but several companies are working on developing such protocols through the use of highly sensitive spectroscopic measurement techniques.

4.1.3 Dig-Ins

The remaining large emissions category is dig-ins – damages to pipelines, mostly from third parties. The dig-in estimates utilized in EPA reporting are currently based on total mileage of mains and services, scaled by a fixed emission factor. The EPA emission factor is based on data from only two or three companies from the early 1990s and would not be reflective of decades of infrastructure integrity improvements such as excess flow valves (EFV), nor extensive public education through damage prevention programs and thus may be overestimated both in terms of frequency and emissions.

An alternative approach would be to use actual data on dig-ins and estimate the amount of gas released. Such calculations typically take into account factors such as:

- Size and shape of damage
- Pipeline pressure
- Time before shut-off or repair
- Deployment of excess flow valves
- Distance from shut-off valve

In limited available data reviewed by ICF, calculated emissions typically average 20 to 60 Mcf of gas released per event. Applying a factor of 35 Mcf to actual dig-in data would result in significantly lower emissions estimates for Nicor Gas and VNG. For Atlanta Gas Light and CGC, this calculated value is similar to the EPA estimate. The actual estimate would be based on the future calculations. GAS already collects data on dig-ins and in some cases does calculate release volumes. This emission reduction measure would only require a systematic structure for collecting, calculating, and reporting the data so the incremental cost would be small when compared to addressing dig-in emissions via carbon offsets. This improved quantification would also better reflect continued company efforts to reduce dig-ins through equipment (such as excess flow valves) and programs to prevent and minimize third party damages and could help to develop and improve those programs.

Table 13 – Dig-In Emissions Estimates (Mt CH_4)

	Nicor Gas	Atlanta Gas Light	VNG	CGC	Total
2019 Emissions	1,945	2,024	342	101	4,412
Potential Emissions After Reductions	1,277	2,024	146	101	3,547

4.1.4 Other Direct Mitigation – Meter and Regulator Stations and Blowdowns

The remaining two, much smaller emission categories are meter and regulator (M&R) stations and blowdowns, 2% and 1% of total emissions respectively. Both are currently based on emission factors but could be based on actual activity and mitigation programs.

There are already LDAR programs for M&R stations driven by different regulatory requirements. The current emissions estimates are based on emission factors developed from annual leak surveys conducted at the larger transmission to distribution (T-D) stations. T-D stations are defined by EPA as those that have transmission pipelines entering the station and distribution pipelines exiting the station. The T-D emission factor is then applied to all other non-T-D M&R stations. A more frequent LDAR program could be developed to better control emissions at these larger stations. The emission reduction cost depends on the frequency of leaks, the size of leaks, cost of labor, and value of gas conserved. Using assumptions from the EPA Lessons Learned document[29] on these measures, the cost of control can range from -\$3/Mt CO_2e (net savings for a single station) to \$30/ Mt CO_2e where all stations are surveyed and only small and infrequent leaks are found and repaired.

Blowdowns occur when gas is vented from pipelines in order to conduct inspections, make repairs, extend the system, or retire pipeline sections. The volume released is dependent on the pipe diameter, pressure, and vented length. The emissions are currently estimated based only on total mileage of mains and services. Mitigating these emissions would start with tracking blowdowns to develop a more accurate estimate of actual emissions as a function of these parameters and continue with specific emission reduction actions.

There are several approaches available to reduce blowdown emissions. For large venting events, the most widely applicable approach is to use portable compressors to move the gas out of the pipe to a different part of the system or to a collection vessel. In some cases, the gas

[29] https://www.epa.gov/sites/production/files/2016-06/documents/ll_dimgatestat.pdf

can be flared rather than recovered. Flaring can be less expensive but results in combustion emissions, loss of gas, and cannot be done in some populated areas.

Renting a large drawdown compressor costs in the range of $25,000 to $60,000. The cost per Mt CO_2e reduced depends on how much gas is recovered and can be an expensive option for smaller pipes and lengths. There are alternative technologies for smaller pipes, such as stoppers and valving, that can be used to more cost-effectively avoid methane releases during maintenance and other potential venting events. In the absence of current data on blowdowns, we assume that mitigating the largest blowdowns would reduce blowdown emissions by 75%.

4.1.5 Methane from Storage Facilities

GAS operates several underground gas storage facilities and LNG storage facilities where gas is stored at high pressure or low temperature for withdrawal and use at peak demand periods. The Nicor Gas Ancona and Troy Grove underground storage facilities are the largest emitters in this category and account for almost all of the methane emissions from the Nicor Gas storage operations as calculated according to EPA emission calculation and reporting methodologies. The majority, 75%, of the emissions at these two facilities were from high bleed pneumatic devices. These are process controllers that are operated by gas pressure and release a small amount of gas as part of normal operation. Replacement of these high bleed controllers with electric driven actuators or zero methane compressed air control systems ("instrument air") would eliminate the 518 Mt CH_4 per year of emissions. Based on an example from the EPA GasSTAR program[30], the value of the recovered gas would offset the cost of the modification, resulting in a net savings and a negative emission reduction cost of $4/Mt CO_2e. Actual feasibility and costs would depend on site-specific factors. Methane emissions from other storage facilities are much smaller.

4.1.6 Summary of Methane Reductions

Table 14 summarizes the potential reduction in estimated methane emissions for the GAS LDC and storage facilities. The largest reductions are from enhanced LDAR and monitoring of meters, followed by pipe replacement, more accurate calculation of dig-in emissions, and reduction of pneumatic device emissions at the storage facilities. The total potential reduction is 33%.

Table 14 - Summary of Potential GAS Methane Reductions (Mt CH_4)

	Pipes	Meters	Dig-Ins	Blowdowns	M&R Stations	Storage	LDC Total
Baseline	13,057	7,687	4,412	283	612	702	26,753
Reductions	1,018	6,150	864	212	136	518	8,898
Remaining	12,039	1,537	3,547	71	476	184	17,854

4.1.7 Methane Capture Offsets

In order to reach its goal of net zero methane emissions, GAS could utilize methane capture or other GHG offsets to mitigate the remaining methane emissions. Offsets are certified and

[30] https://www.epa.gov/sites/production/files/2016-06/documents/ll_instrument_air.pdf

creditable reductions of existing methane emissions created according to strict protocols. The reductions must be in addition to reductions already occurring or required by regulation and must be carefully and transparently measured and verified. Offsets of this kind are widely accepted in emission cap and trade programs such as the California, RGGI, and European Union cap and trade programs.

Once a project has been identified, the developer identifies an appropriate offset creation protocol from one of the certification organizations. The developer can engage a third-party auditor to verify the reductions. If desired the analysis can be submitted to one of the certification organizations. In that case, the developer can periodically submit the data to quantify and be awarded creditable offsets by the certifier. The original verification would ensure that the reductions are surplus and establish the parameters for ongoing quantification. For RNG projects, the primary factor would be the amount of methane produced and captured versus the emissions that would have otherwise occurred. The creditable offsets will be discounted somewhat to account for losses and emissions associated with capturing and processing the methane.

The most likely source for methane capture offsets would be from dairy and swine operations. ICF has estimated the volumes that could be available from these sources in its renewable natural gas estimate (see Section 3.5). Table 15 shows the amount of remaining methane emissions for each company and the potential methane capture offsets estimated to be available in each service territory. In some cases (VNG and CGC) offsets would need to be acquired from outside the service territory.

Table 15 – Methane Offsets for Remaining Methane Emissions (1000 Mt CO_2e)

	Nicor Gas	Atlanta Gas Light	VNG	CGC
Remaining CH_4 Emissions	183	219	34	11
Potential Methane Offsets	750 to 1,726	94 to 328	2.4	7

4.2 CO_2 From Combustion

4.2.1 Storage

Beyond methane emissions, there are CO_2 emissions. The majority of GAS' CO_2 emissions are from the gas-fired compressors and electricity generators at its underground and LNG storage facilities. There are three options to address these emissions:

- Fueling the compressors and generators with CO_2-neutral RNG.
- Offsetting the emissions with methane capture from RNG production.
- Replacing the gas-fired compressors with electric compressors. This would require a significant capital investment. A simple replacement project could cost in the range of $10 to $15 million based on a similar project described in the EPA Natural Gas STAR

program.[31] However GAS estimates that including electricity upgrades and support systems and auxiliaries could increase costs to as much as $30 million per compressor. If the replacement is part of the normal equipment turnover schedule, the incremental cost could be lower. A more detailed analysis would be required for a more accurate cost estimate. Maintenance costs for electric compressors are typically lower than for gas-fired equipment. On the other hand, storage facilities must be available to operate at all times, especially during winter conditions when electric outages may be more likely. Electrification would require installation of back-up generators to ensure reliability, which could add significantly to the cost. Electrification would eliminate direct emissions but increase indirect emissions related to electricity consumption. The indirect emissions would decline over time if and when grid emissions are reduced. The larger storage facilities have multiple compressors so it could be possible to implement multiple solutions (i.e., RNG and electrification) and/or phase them in over time.

4.2.2 Fleet Emissions

The LDCs maintain fleets of vehicles for a variety of purposes, ranging from light duty vehicles for company business travel, meter readers and other customer services, to light and medium duty trucks for maintenance and repair operations. This does not include leased or contracted equipment. Although much smaller than the other direct emissions components, there are opportunities to reduce the emissions from these vehicles. The exact mix of these options is not projected here.

Demand reduction – The lowest cost and most immediate opportunity is to use the existing fleet more efficiently by eliminating unnecessary trips and optimizing planned trips. This is highly company-specific and will need to be developed through a dedicated analysis.

Alternative Fuel Options

Table 16 shows the comparison between emissions from different light duty vehicle/fuel options based on analysis using the Argonne National Laboratory Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) 2020 model.[32] These comparisons are “well to wheels” meaning that they incorporate all of the upstream emissions as well as the vehicle efficiency.

CNG/RNG vehicles – Compressed natural gas (CNG) can be used in slightly modified conventional engines and is already commercially available and in use for light and medium duty vehicles. CNG reduces CO_2 emissions by 23% compared to gasoline. It also reduces emissions of conventional pollutants, including black carbon, which is a potent climate forcer. GAS is already using CNG vehicles and operates the required fuel infrastructure. CO_2-neutral RNG could be applied using the same fueling and vehicle infrastructure to achieve much lower (-86%) or negative emissions (-127% including upstream methane reductions). The compressed RNG from dairies is the lowest emissions option and is fully commercial today.

[31] https://www.epa.gov/natural-gas-star-program/install-electric-compressors
[32] https://greet.es.anl.gov/

Table 16 – Well to Wheels (WTW) Light Duty Vehicle Emissions

		WTW Carbon Intensity (gCO_2e/mi):	% Reduction from Gasoline per mile
Petroleum	Gasoline	406	NA
CNG	North American Natural Gas	315	-22.5%
RNG	Landfill Gas (LFG) RNG	59	-85.5%
	Dairy Cow Animal Waste RNG	-113	-127.7%
Electric Vehicle	U.S. Mix Electricity	153	-62.4%
	RFC Mix Electricity	154	-62.0%
	Renewable Mix Electricity	1	-99.8%
Hybrid Electric Vehicle	Gasoline (Grid-Independent)	292	-28.2%
Plug-in Hybrid Electric Vehicle	Gasoline & U.S. Mix Electricity	231	-43.1%
	Gasoline & RFC Mix Electricity	232	-42.8%
	Renewable Mix Electricity	123	-69.8%
Hydrogen Fuel Cell	Conventional (NG SMR) Gaseous H2; Central Plant Production	182	-55.3%
	Electrolyzed Gaseous H2 (U.S. Mix); Refueling Station Production	351	-13.5%
	Electrolyzed Gaseous H2 (RFC Mix); Refueling Station Production	355	-12.6%
	Electrolyzed Gaseous H2 (Renewable Mix); Refueling Station Production	2	-99.6%

Data Source: GREET

Hybrids, Plug-in Hybrid, and Electric Vehicles – This range of vehicles represents a transition to vehicles increasingly reliant on electricity rather than fossil fuel. Electrification removes the emissions from the company's direct emissions footprint but increases indirect emissions and only reduces total emissions to the extent that the electric grid becomes decarbonized. However, this becomes a viable option over time as that happens. At current regional electric grid emission rates, the plug-in vehicles reduce emissions by roughly 40% to 60% compared to gasoline. With a highly renewable-based grid, the reductions could be in the 70% to 100% range. There is a limited array of these vehicles currently available, however many new light and medium duty electric vehicles will be entering the market in the next five to ten years.

Hydrogen Fuel Cell – Hydrogen fuel cell electric vehicles are more developmental but could be attractive if hydrogen is more available. They could have emissions 100% lower than gasoline if renewable-based hydrogen were available.

5 Mitigation of Indirect Emissions

5.1 Customer Emissions

As discussed earlier, emissions from customer use of gas were many times higher than 2019 direct emissions. Residential and commercial customers comprised 97% of GAS' sales volumes and 67% of total deliveries. With appropriate regulatory approval and support, GAS is uniquely positioned to assist with decarbonization of the use of energy by these customers through a combined strategy of:

- Improved building efficiency
- Improved appliance efficiency (space heating and water heating)
- Use of RNG, P2G, and/or methane or carbon offsets for the remaining gas demand.

Nicor Gas and VNG have existing energy efficiency programs. To assess the potential for further GHG reduction for residential and commercial customers through these pathways, ICF modeled several scenarios. First were two scenarios based on energy efficiency, RNG and offsets, and gas-based technologies for the residential and commercial sectors through 2050. Second were two scenarios based on policy-driven mandatory electrification of these sectors, as is being proposed by some stakeholders. One of these is a pure electrification scenario while the other uses a hybrid technology approach in which gas technology is used as a back-up to the mandatory electric technology.

5.1.1 Analysis of Natural Gas Decarbonization Scenarios

Table 17 summarizes the natural gas-based scenarios. Scenario 1 is a more conventional scenario with less extensive building efficiency measures and conventional high efficiency gas appliances for space and water heating. Scenario 2 has more extensive building measures and more efficient natural gas heat pumps for space and water heating. Gas heat pumps are a technology currently being commercialized, which, similar to electric heat pumps, can offer efficiencies greater than 100% by transferring heat from outside to inside, rather than producing heat directly from combustion.[33] These scenarios also included the use of CO_2-neutral RNG to fuel the gas appliances and methane capture GHG offsets from RNG projects to net out some of the emissions. Table 18 provides more detail on the equipment and cost assumptions for these scenarios.

[33] More information on gas heat pumps available at: https://www.gti.energy/wp-content/uploads/2020/09/Gas-Heat-Pump-Roadmap-Industry-White-Paper_Nov2019.pdf

Table 17 – Natural Gas Scenarios for Customer Modeling

	Scenario 1	Scenario 2
Sub-Sector Groupings	**Conventional Efficiency Options/RNG**	**High Efficiency Gas Technologies/RNG**
Single family Multifamily Small commercial	New Construction - Improved building shells (~40%)	New Construction - Net-zero Ready Homes (~80% reduction)
	Existing Building Retrofits – Building shell improvements (~15%)	Existing Building Retrofits – Deep Energy (~30% reduction)
	High efficiency gas furnace	Gas Heat Pump (space heating)
	Tankless water heaters	Gas Heat Pump (water heating)
	Smart thermostats	Smart thermostats
	Home energy reports	Home energy reports
	Energy saving kits	Energy saving kits
	EnergyStar gas appliances	EnergyStar gas appliances
Large commercial Institutional	New Construction - Improved building shells (~40%)	New Construction - Net-zero Ready (~80% reduction)
	Existing Building Retrofits – Building shell improvements (~5%)	Existing Building Retrofits – Deep Energy (~25% reduction)
	High efficiency furnaces/boilers	Gas heat pumps
	Smart building controls, behavioral reductions, re-commissioning	Smart building controls, behavioral reductions, re-commissioning

Table 18 - Summary of Scenario 1 and 2 Equipment Cost and Performance Assumptions

Sector	Sub-Sector	Vintage	End Use	Measure Name	Upfront Incremental Cost per unit	% Savings
Residential	Single Family	Existing	Space Heating	Existing Building Retrofits – Building shell improvements (20%)	$ 3,050	15%
				Existing Building Retrofits – Deep Energy (40% reduction)	$ 10,000	30%
				Retrofit - Gas Furnaces to Gas Heat Pumps for Space Heating	$ 4,859	43%
				Retrofit - Gas Furnaces to High Efficiency Gas Furnaces / boiler	$ 808	16%
			DHW	Retrofit - EnergyStar Tank Water Heater	$ 400	24%
				Retrofit - Natural Gas Heat Pump Water Heater	$ 1,636	55%
				Retrofit - Tankless Water Heaters	$ 605	32%
		New Residential Construction	Space Heating	New Construction - Gas Heat Pumps for Space Heating	$ 4,859	36%
				New Construction - High Efficiency Gas Furnaces / boiler	$ 808	5%
				New Construction - Improved building shells (40%)	$ 4,684	40%
				New Construction - Net-zero Ready Homes (80% reduction)	$ 24,089	80%
			DHW	New Construction - EnergyStar Tank Water Heater	$ 400	3%
				New Construction - Natural Gas Heat Pump Water Heater	$ 1,636	42%
				New Construction - Tankless Water Heaters	$ 605	13%
	Multi-family	Existing	Space Heating	Existing Building Retrofits – Building shell improvements (20%)	$ 388	5%
				Existing Building Retrofits – Deep Energy (40% reduction)	$ 2,025	25%
				Retrofit - Gas Furnaces to Gas Heat Pumps for Space Heating	$ 2,564	37%
				Retrofit - Gas Furnaces to High Efficiency Gas Furnaces / boiler	$ 2,135	14%
			DHW	Retrofit - EnergyStar Tank Water Heater	$ 400	24%
				Retrofit - Natural Gas Heat Pump Water Heater	$ 1,636	55%
				Retrofit - Tankless Water Heaters	$ 605	32%
		New Construction	Space Heating	New Construction - Gas Heat Pumps for Space Heating	$ 2,564	37%
				New Construction - High Efficiency Gas Furnaces / boiler	$ 2,135	14%

				New Construction - Improved building shells (40%)	$ 1,115	40%
				New Construction - Net-zero Ready Homes (80% reduction)	$ 4,740	80%
			DHW	New Construction - EnergyStar Tank Water Heater	$ 400	3%
				New Construction - Natural Gas Heat Pump Water Heater	$ 1,636	42%
				New Construction - Tankless Water Heaters	$ 605	13%
Commercial	Small	Existing	Space Heating	Existing Building Retrofits – Building shell improvements (20%)	$ 56,506	5%
				Existing Building Retrofits – Deep Energy (40% reduction)	$ 151,973	25%
				Retrofit - Gas Furnaces to Gas Heat Pumps for Space Heating	$ 57,189	37%
				Retrofit - Gas Furnaces to High Efficiency Gas Furnaces / boiler	$ 42,379	14%
			DHW	Retrofit - EnergyStar Tank Water Heater	$ 3,418	21%
				Retrofit - Natural Gas Heat Pump Water Heater	$ 4,908	42%
				Retrofit - Tankless Water Heaters	$ 2,526	20%
		New Construction	Space Heating	New Construction - Gas Furnaces to Gas Heat Pumps for Space Heating	$ 57,189	31%
				New Construction - Gas Furnaces to High Efficiency Gas Furnaces / boiler	$ 42,379	5%
				New Construction - Improved building shells (40%)	$ 148,328	40%
				New Construction - Net-zero Ready Buildings (80% reduction)	$ 296,883	80%
			DHW	New Construction - Natural Gas Heat Pump Water Heater	$ 4,908	38%
				New Construction - Tankless Water Heaters	$ 2,526	16%
				New Construction - EnergyStar Tank Water Heater	$ 3,418	17%
	Large	Existing	Space Heating	Existing Building Retrofits – Building shell improvements (20%)	$ 565,058	5%
				Existing Building Retrofits – Deep Energy (40% reduction)	$ 1,519,733	25%
				Retrofit - Gas Furnaces to Gas Heat Pumps for Space Heating	$ 571,893	37%
				Retrofit - Gas Furnaces to High Efficiency Gas Furnaces / boiler	$ 423,794	14%
			DHW	Retrofit - EnergyStar Tank Water Heater	$ 34,177	17%
				Retrofit - Natural Gas Heat Pump Water Heater	$ 105,025	38%
				Retrofit - Tankless Water Heaters	$ 66,075	16%
		New Construction	Space Heating	New Construction - Gas Furnaces to Gas Heat Pumps for Space Heating	$ 571,893	31%
				New Construction - Gas Furnaces to High Efficiency Gas Furnaces / boiler	$ 423,794	5%
				New Construction - Improved building shells (40%)	$ 1,483,277	40%
				New Construction - Net-zero Ready Buildings (80% reduction)	$ 2,968,833	80%
			DHW	New Construction - Natural Gas Heat Pump Water Heater	$ 105,025	38%
				New Construction - Tankless Water Heaters	$ 66,075	16%
				New Construction - EnergyStar Tank Water Heater	$ 34,177	17%

5.1.2 Analysis of Electric Decarbonization Options

While there is a viable natural gas-based decarbonization pathway, there has also been discussion of a policy-driven mandatory electrification pathway. In this approach, end uses, especially space heating, would be forced to convert to electric technology either on initial construction or at equipment replacement. This approach would eliminate emissions from affected facilities if, as assumed in this analysis, the electricity supply is completely decarbonized. The electrification would increase electricity demand which could affect the cost of electricity supply and resulting electricity prices and should be evaluated to understand the implications of this approach.

The emissions benefit of electrification would depend on rapid and deep decarbonization of the electric grid. The cost and emissions of electricity relative to gas would depend on the cost and emissions of electricity and the cost and efficiency of the consumer equipment. Table 19 compares current gas and electricity prices and average emissions on a consistent per MMBtu basis for each state. It shows that electricity prices are currently roughly two to five times higher than gas prices on an energy basis and current average electricity CO_2 emissions are almost twice as high as natural gas emissions per energy unit.

Table 19 - Comparison of Natural Gas Electricity Cost and Emissions [34]

	Gas		Electricity			
	$/MMBtu	kg CO_2 /MMBtu	$/kWh	$/MMBtu	kg CO_2 /MWh	kg CO_2 /MMBtu
Nicor Gas						
Residential	$8.04	53	$0.133	$38.97	342	100
Commercial	$7.02	53	$0.100	$29.18	342	100
Industrial	$5.25	53	$0.066	$19.28	342	100
Atlanta Gas Light						
Residential	$14.87	53	$0.12	$34.46	397	116.3
Commercial	$8.21	53	$0.10	$28.68	397	116.3
Industrial	$4.42	53	$0.06	$17.58	397	116.3
VNG						
Residential	$12.62	53	$0.10	$27.89	309	90.5
Commercial	$8.53	53	$0.08	$23.97	309	90.5
Industrial	$4.66	53	$0.07	$20.10	309	90.5
CGC						
Residential	$9.45	53	$0.10	$28.39	332	97.3
Commercial	$8.10	53	$0.11	$31.85	332	97.3
Industrial	$4.68	53	$0.11	$31.20	332	97.3

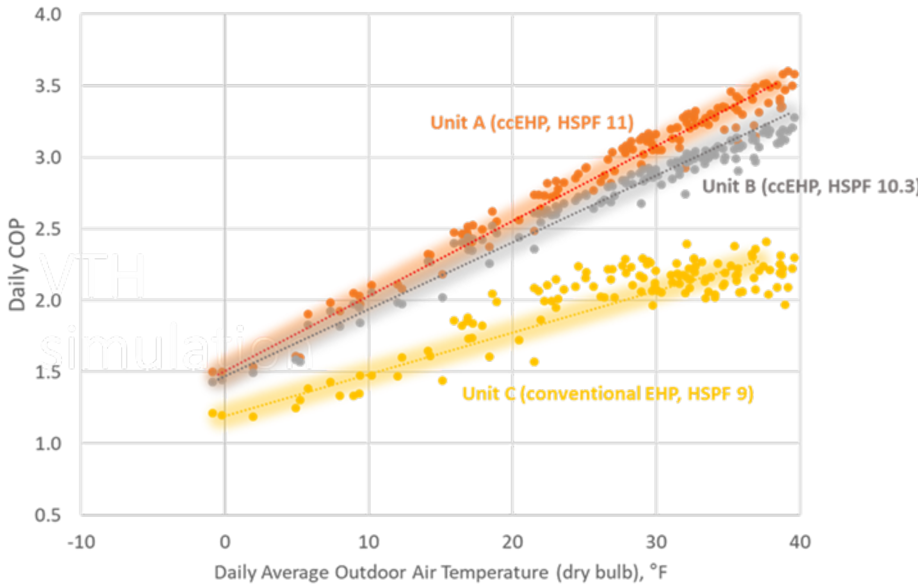
This situation would make electrification more expensive and higher-emitting if the gas and electric consumer equipment had the same efficiency. The factor that makes electrification a potentially advantageous option is the use of air source heat pumps (ASHP) for space heating or heat pump water heaters (HPWH). Heat pumps use electricity to move heat from outside to inside, rather than using the energy to directly heat the house. This allows heat pumps to have seasonal efficiencies on the order of 300% to 400% compared to 98% for the most efficient conventional gas furnaces. This can help to overcome the gap between electricity and gas prices and emissions. In other applications where the electric technology does not have this performance advantage (like electric resistance heating), the price and emissions gap will make electric technology higher emitting and much more expensive today. If and when the electric grid decarbonizes, emissions will go down though electric prices might increase.

While the heat pump's seasonal efficiency can be quite high, the efficiency is lower as the outdoor temperature drops. At very cold temperatures, the heat pump might need to rely on much less efficient resistance heat. Newer cold climate heat pumps are more efficient at lower temperatures but still see performance decline significantly at very cold temperatures,

[34] Data Sources: Electricity prices:
https://www.eia.gov/electricity/data/browser/#/topic/7?agg=0,1&geo=g0000001&endsec=vg&freq=A&start=2001&end=2020&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin= ,
Gas prices: https://www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_PRS_DMcf_a.htm,
Electricity emissions: https://www.eia.gov/electricity/data/emissions/xls/emissions_region2019.xlsx,
Gas emissions: EPA GHGRP

increasingly relying on back-up resistance heat (COP=1) as temperatures drop below zero, as shown in Figure 15.

Figure 15 - Heat Pump Performance Declines With Colder Temperatures



Source: Gas Technology Institute

Widespread heat pump use could therefore result in high electric demand peaks during periods of very cold weather. Even outside of cold weather demand peaks, wide-spread mandatory application of electric heat pumps would greatly increase electric consumption and possibly peak demand, potentially requiring large increases in electric generating, transmission, and distribution capacity. This will be further discussed in the context of the analytical results.

While there are uncertainties on how deep decarbonization of the electricity sector would progress in a way that would make electrification an advantageous pathway for buildings, this analysis assumes that such policies would be put in place and focuses on applications in which electric heat pumps would be applicable in ways that would result in lower emissions and more reasonable costs. This includes single family and smaller multifamily buildings and smaller commercial and industrial buildings. Table 20 summarizes the two electrification scenarios that were analyzed. Scenario 3 is a pure policy-driven mandatory electrification scenario and includes assumptions on the additional electricity infrastructure that would be required to meet both the increased baseline energy consumption and the high peaks associated with unusually cold weather.

Scenario 4 illustrates a case using a hybrid gas/electric heating technology in which heat pumps are used for most of the heating load but a gas furnace with RNG is used during very cold weather periods to avoid a high electric demand spike and the associated infrastructure costs. While this would address the peaking issues on the electric side (and maintain use of the gas system), it would dramatically shift the operations of the gas system to operate primarily as a winter peaking service, which would entail operational considerations and potential cost considerations. GAS would need to continue to invest in the gas system to maintain safety and reliability of the system and (under this scenario) integrate low carbon fuels like RNG, but the costs would be spread over a diminishing customer and consumption base. These cost and operational considerations would need to be considered in comparison to the implications of other approaches analyzed in this study.

Table 20 – Electric Scenarios for Customer Modeling

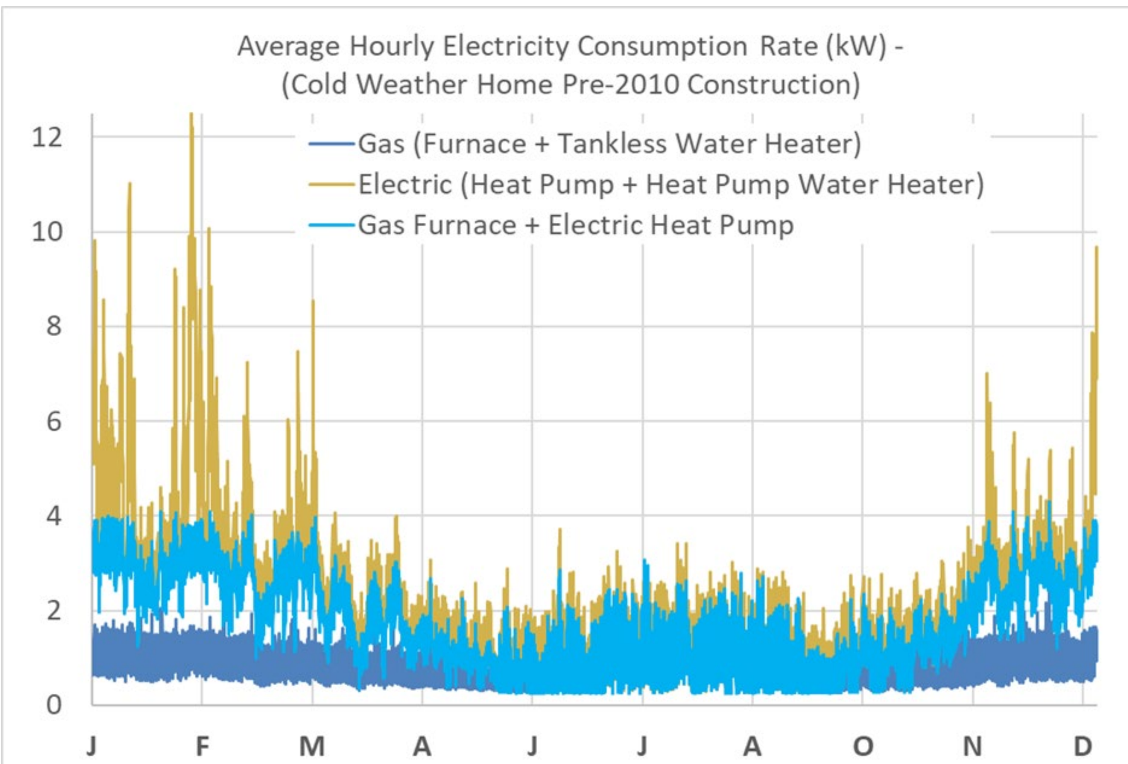
	Scenario 3	Scenario 4
Sub-Sector Groupings	**Policy-Driven Mandatory Electrification**	**Gas/Electric Hybrid Approach**
Single family Multifamily Small commercial	New Construction - Net-zero Ready Homes (~80% reduction)	New Construction - Net-zero Ready Homes (~80% reduction)
	Existing Building Retrofits – Deep Energy (~30% reduction)	Existing Building Retrofits – Deep Energy (~30% reduction)
	Electric ASHP	Hybrid gas-electric (ASHP + gas backup)
	Electric resistance heating and boilers (space heating)	High efficiency furnaces / boilers (space heating)
	Mix of HPWH & electric resistance water heating	Mix of tankless gas units and electric HPWH
	Smart thermostats	Smart thermostats
	Home energy reports	Home energy reports
	Energy saving kits	Energy saving kits
	Electric appliances	EnergyStar gas appliances
Large commercial Institutional	New Construction - Improved building shells (~40%)	New Construction - Net-zero Ready (~80% reduction)
	Existing Building Retrofits – Deep Energy (~25% reduction)	Existing Building Retrofits – Deep Energy (~25% reduction)
	Electric ASHP, Electric Boilers	Hybrid gas-electric (ASHP + gas backup)
	Electric Boilers (space heating)	High efficiency boilers (space heating)
	Mix of HPWH & electric resistance water heating	Mix of high efficiency gas boilers and electric HPWH
	Smart building controls, behavioral reductions, re-commissioning	Smart building controls, behavioral reductions, re-commissioning

The majority of the electric space heating installations are air source heat pumps, but there is a small share of electric resistance heating in applications where the ASHP is not expected to be feasible. The resistance heat portion is larger in the commercial segment, especially in large commercial and institutional settings where electrification can be less disruptive if an electric boiler continues to feed the existing hydronic systems. The upfront costs for these electric resistance systems are significantly lower, particularly where they leverage existing infrastructure in buildings, but their efficiencies are three to four times lower, leading to higher energy costs than for the ASHP systems. Some of the multifamily and commercial heat pumps are also more expensive, as they require extensive building modifications to install variable refrigerant flow (VRF) systems.

Given the levels of reduction for natural gas customers in the Policy-Driven Mandatory Electrification Scenario, it would likely require a wind-down of the natural gas distribution infrastructure, even if not all customers were transitioned off the system by 2050. For that reason, Scenario 3 does not include RNG to decarbonize the remaining natural gas demand, while Scenario 4, which does envision an important role for natural gas distribution infrastructure, leverages RNG to decarbonize the remaining natural gas demand. For this reason, the Gas/Electric Hybrid Scenario is able to achieve larger emission reductions by 2050 than the Policy-Driven Mandatory Electrification Scenario assumed here.

Mandatory electrification of residential and commercial space and water heating would result in a large increase in electricity consumption and potentially in peak demand during peak heating conditions when the heat pumps are less efficient. Figure 16 illustrates the value of gas back-up in limiting electric peak demand during periods of high heating demand. The hybrid technology scenario models this approach to electrification with reduced peak demand.

Figure 16 - Gas/Electric Hybrid Systems Can Reduce Electric Demand Peaks



Source: Gas Technology Institute

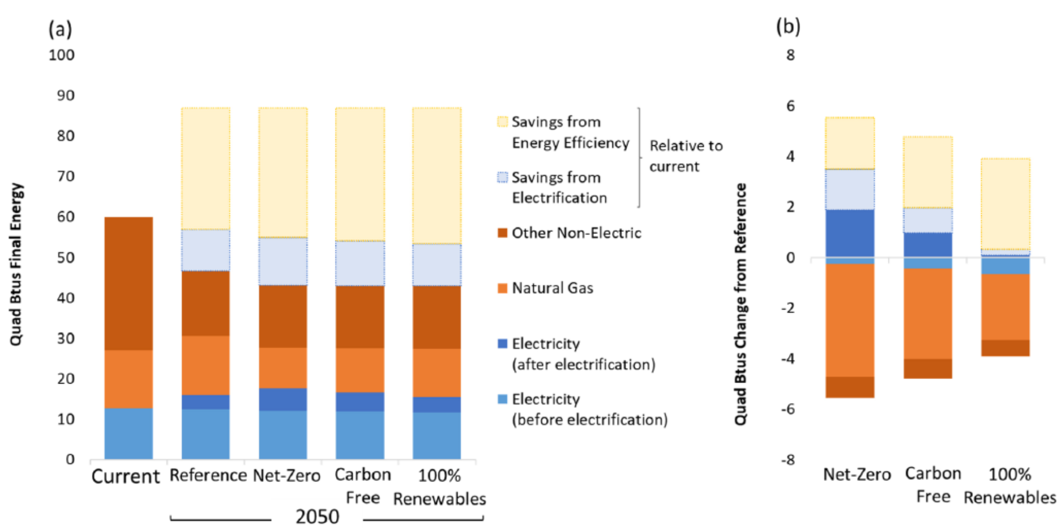
Providing increased electric supply is complicated in this case by the need to be decarbonizing the grid at the same time. Decarbonization will require retirement of fossil fuel generators or implementation of other solutions like carbon capture and storage, which would need to be addressed along with the additional new capacity required to meet increased demand for electrification. The Virginia Clean Economy Act (VCEA), in particular, is expected to rely in large part on development of off-shore wind generation. New renewable generation will also require back-up capacity for periods of low generation. The local distribution grid may also require upgrades not only for the assumed heating systems but also for vehicle electrification. Finally, the scenario implies the replacement of hundreds of thousands of customer heating systems over 30 years.

The costs of electric system decarbonization and the additional costs to support mandatory end use electrification will be significant. For this analysis, there is the further complexity of converting the capital cost to an effect on consumer costs. In some cases, investments to meet increased electricity consumption do not result in higher consumer per kWh rates because the increased consumption pays for the expenditures. Although there is uncertainty on how costs of decarbonization and increased electrification will impact the cost of electricity, there are reasons this may not be as true in this case, including:

- A requirement to prematurely retire or otherwise address fossil generators may increase the required expenditures needed to meet new and increasing demand.
- The weather-dependent electric heating systems will be very "peaky", reducing the average utilization of the system.
- Increased reliance on renewable generators will reduce the utilization factor of the generating system and require increased back-up equipment, such as battery storage.

The estimate of consumer price impacts used for this analysis was based on an EPRI analysis that analyzed the cost of decarbonization on the electric system.[35] That said, the EPRI study does not really focus on end use electrification or distribution impacts of increased peak load. For example, in their '100% renewables case' (Figure 17) there is only modest end use electrification occurring. Since this is the scenario with the highest electric cost increase, it also assumes less electrification in that scenario (more energy efficiency instead).

Figure 17 - EPRI Decarbonization Analysis Results[35]



[35] "Powering Decarbonization: Strategies for Net-Zero CO_2 Emissions", EPRI, February 2021.

The ICF customer analysis uses different electric price impacts for different scenarios, based on the level of electrification and peak demand impact of different scenarios. ICF had calculated a 'reference case' for residential and commercial electricity prices, based on EIA data showing average residential and commercial electric rates for 2019 and adjusting them out to 2050 based on trends in the EIA Annual Energy Outlook. (The AEO reference case residential rates decline 7% by 2050, commercial rates decline 15% by 2050).

ICF in collaboration with the client developed a range of potential electricity price impacts based on the EPRI analysis and the implications of further electrification in addition to the scenarios considered in the EPRI analysis. ICF then allocated values from that range to the different scenarios in this study. ICF added these 'incremental cost elements' to the reference case (declining) electric rates as shown in Table 21. The cost increase grows linearly starting in 2026 building up to the total 2050 incremental cost (so adding another 1/25th of the total increase each year from 2026 to 2050).

Table 21 – Scenario Electricity Price Drivers

Scenario	Drivers between scenarios	Res/Com Rate increase for Modeling
1	• No mandatory electrification of space heating • Assume grid is decarbonizing (as we pursue net zero targets) • Assume vehicles are electrifying (as we pursue net zero targets)	+2.5 cents/ kWh in 2050
2	• No mandatory electrification of space heating • Assume grid is decarbonizing (as we pursue net zero targets) • Assume vehicles are electrifying (as we pursue net zero targets)	+2.5 cents/ kWh in 2050
3	• Majority of space heating is electrified, driving an increase in winter peak demand • Assume grid is net zero GHG emissions by 2050 • Assume vehicles are electrifying (as we pursue net zero targets)	+6 cents/ kWh in 2050 (Atlanta Gas Light, VNG, CGC) +6.5 cents/ kWh in 2050 (Nicor Gas)
4	• Large portion of space heating is electrified, but maintains gas back-up heating, minimizing peak demand impacts • Assume grid is net zero GHG emissions by 2050 • Assume vehicles are electrifying (as we pursue net zero targets)	+3 cents/ kWh in 2050

The other critical component of the electrification scenario is the grid decarbonization trajectory. There is no externally available reference for an electric scenario for grid decarbonization that achieves net zero emissions from power generation in 2050. ICF reviewed one scenario from EIA that achieved an 80% reduction in 2050 through a $35/tonne CO_2 tax. Ultimately, ICF defined a trajectory that achieves net zero emissions by 2050, based on a linear trajectory from 2019 average GHG intensity.

If decarbonization of the power sector is delayed, then the costs and benefits of electrification will be delayed and diminished. If decarbonization is accelerated by policy or otherwise, then the benefits of electrification will be accelerated but may be at higher cost to customers.

Table 22 summarizes the equipment cost and performance assumptions for these scenarios.

Table 22 - Summary of Scenario 3 and 4 Equipment Cost and Performance Assumptions

Sector	Sub-Sector	Vintage	End Use	Measure Name	Upfront Incremental Cost per unit	% Savings
Residential	Single Family	Existing	Space Heating	Electric ASHP	$ 681	100%
				Existing Building Retrofits – Building shell improvements (20%)	$ 3,050	15%
				Existing Building Retrofits – Deep Energy (40% reduction)	$ 10,000	30%
				Hybrid gas-electric (ASHP with gas backup)	$ 1,740	75%
			DHW	Electric Heat Pump Water Heater	$ 2,502	100%
				Electric Resistance Water Heater	$ 705	100%
		New Construction	Space Heating	Electric ASHP	$ (151)	100%
				Hybrid gas-electric (ASHP with gas backup)	$ 1,632	75%
				New Construction - Improved building shells (40%)	$ 4,684	40%
				New Construction - Net-zero Ready Homes (80% reduction)	$ 24,089	80%
			DHW	Electric Heat Pump Water Heater	$ 2,502	100%
				Electric Resistance Water Heater	$ 705	100%
	Multi-family	Existing	Space Heating	Electric ASHP	$ 1,464	100%
				Existing Building Retrofits – Building shell improvements (20%)	$ 388	5%
				Existing Building Retrofits – Deep Energy (40% reduction)	$ 2,025	25%
				Hybrid gas-electric (ASHP with gas backup)	$ 1,664	75%
			DHW	Electric Heat Pump Water Heater	$ 2,502	100%
				Electric Resistance Water Heater	$ 705	100%
				Retrofit - EnergyStar Tank Water Heater	$ 400	24%
				Retrofit - Natural Gas Heat Pump Water Heater	$ 1,636	55%
				Retrofit - Tankless Water Heaters	$ 605	32%
		New Construction	Space Heating	Electric ASHP	$ 348	100%
				Hybrid gas-electric (ASHP with gas backup)	$ 548	75%
				New Construction - Improved building shells (40%)	$ 1,115	40%
				New Construction - Net-zero Ready Homes (80% reduction)	$ 4,740	80%
			DHW	Electric Heat Pump Water Heater	$ 2,502	100%
				Electric Resistance Water Heater	$ 705	100%
Commercial	Small	Existing	Space Heating	Electric ASHP	$ 170,201	100%
				Existing Building Retrofits – Building shell improvements (20%)	$ 56,506	5%
				Existing Building Retrofits – Deep Energy (40% reduction)	$ 151,973	25%
				Hybrid gas-electric (ASHP with gas backup)	$ 208,935	75%
			DHW	Electric Heat Pump Water Heater	$ 7,506	100%
				Electric Resistance Water Heater	$ 2,115	100%
		New Construction	Space Heating	Electric ASHP	$ 42,607	100%
				Hybrid gas-electric (ASHP with gas backup)	$ 77,240	75%
				New Construction - Building Control System	$ 638	5%
				New Construction - Improved building shells (40%)	$ 148,328	40%
				New Construction - Net-zero Ready Buildings (80% reduction)	$ 296,883	80%
			DHW	Electric Heat Pump Water Heater	$ 7,506	100%
				Electric Resistance Water Heater	$ 2,115	100%
	Large	Existing	Space Heating	Electric ASHP	$ 7,669,296	100%
				Existing Building Retrofits – Building shell improvements (20%)	$ 565,058	5%
				Existing Building Retrofits – Deep Energy (40% reduction)	$ 1,519,733	25%
				Hybrid gas-electric (ASHP with gas backup)	$ 7,801,447	75%
			DHW	Electric Heat Pump Water Heater	$ 105,025	100%
				Electric Resistance Water Heater	$ 44,457	100%
				Retrofit - EnergyStar Tank Water Heater	$ 34,177	17%
		New Construction	Space Heating	Electric ASHP	$ 4,240,214	100%
				Hybrid gas-electric (ASHP with gas backup)	$ 4,372,365	75%
				New Construction - Improved building shells (40%)	$ 1,483,277	40%
				New Construction - Net-zero Ready Buildings (80% reduction)	$ 2,968,833	80%
			DHW	Electric Heat Pump Water Heater	$ 105,025	100%
				Electric Resistance Water Heater	$ 44,457	100%

5.1.3 Results of Customer Modeling

The detailed results of the customer modeling are presented for each company in Chapters 10 through 13 and are summarized in Table 23. The gas-based scenarios including RNG are projected to yield the greatest reductions in GHG emissions and are also less expensive than the mandatory electrification scenario. This results in a $/tonne cost of reduction that is roughly half as much for the two gas-only scenarios as for the mandatory electrification scenario.

Table 23 - Summary of Customer Modeling Scenarios – All Companies

	2020	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
	Base Year	Conventional Efficiency Options	High Efficiency Gas Technologies	Policy Driven Mandatory Electrification	Gas/Electric Hybrid Approaches
2050 Gas Consumption (Million MMBtu)	580	524.60	419.92	128.54	297.76
2050 Reduction in Gas Consumption vs. 2020 Base Year (%)		-4%	-23%	-76%	-45%
2050 Reduction in Gas Consumption vs. 2050 Reference Case (%)		-18%	-34%	-80%	-53%
2050 GHG Emissions (million tCO_2 / year)	30.8	5.16	0.53	6.82	0.08
2050 Reduction in GHG Emissions vs. 2020 Base Year (%)		-82%	-98%	-76%	-100%
2050 Reduction in GHG Emissions vs. 2050 Reference Case (%)		-85%	-98%	-80%	-100%
Total Costs - NPV of Equipment and 2020-2080 Incremental Energy Costs ($2020 Millions)		$112,020	$129,411	$228,168	$171,321
NPV of 2020 to 2080 GHG Emission Reductions (million tCO_2)		430	495	391	502
Emission Reduction Costs ($/$tCO_2$)		$260	$262	$584	$341

5.2 Large Industrial Customers

As noted earlier, each company had large industrial gas deliveries in 2019 to a small number of industrial customers with large, base load process operations. For VNG, this includes large defense facilities with high reliability requirements. The decarbonization options for these applications are more limited than for the small space heating customers. Large industrial customers have typically already optimized their energy processes to maximize their profitability. While there could be additional improvements, they are typically small. Replacing large process equipment with new equipment is very expensive and typically not economically feasible for manufacturers who usually have limited capital.

There are also more limited electrification options, if any, and most of these technologies do not have the high efficiency advantage of the heat pumps available for residential space heating applications. Because electricity in 2019 was roughly two to five times more expensive than gas on a Btu basis (see Table 19), electrification would result in dramatically higher energy costs for manufacturers. For example, while it would be technically feasible to use electric boilers to produce steam, their efficiency is only in the high 90% range, only slightly higher than a conventional boiler but with a several-fold increase in energy price. Electro-technologies for other processes are less developed and some are not significantly more efficient than gas technologies to offset large investment costs and large increases in energy costs.

Electrification would also require large investments in electricity generation and infrastructure. Table 24 summarizes the amount of base load electric capacity[36] that would be required to replace gas delivered to large industrials in each service territory and the equivalent cost of a new gas combined cycle at $1000/kW[37] of capacity. In a decarbonizing scenario such as for offshore wind capacity, the total cost would be even higher due to higher capital costs and lower capacity factor.

Table 24 - Electric Demand to Replace Industrial Consumption

	Nicor Gas	Atlanta Gas Light	VNG	CGC
Electric Equivalent Demand (MW)	4,800	2,600	500	400
Potential Electric Capacity Cost ($M)	$4,800	$2,600	$500	$400

Alternative options might be the use of low-GHG fuels, such as RNG or, with limited modifications, renewable-based hydrogen, that could be used in existing equipment. Industrial customers who are already procuring their own fuel, could instead purchase RNG. RNG could be delivered via the existing gas transmission network and GAS distribution system and used in existing combustion equipment.

Hydrogen or methane produced from hydrogen (P2G) are also options. One hydrogen option would be to produce hydrogen on-site from renewable-based electricity. Large industrial facilities could have sufficient base-load demand to potentially make this equipment cost-effective. If there are several large industrial facilities in a reasonable proximity, this kind of “hydrogen island” could be even more cost-effective. Southern Company Gas is at the forefront of supporting research and development on hydrogen technology as a low-GHG fuel and could assist customers with the implementation of RNG and/or hydrogen systems.[38] Another option for large industrial facilities or groups of facilities would be the use of conventional natural gas with carbon capture and sequestration.

One readily available technology that can help to utilize RNG, and potentially hydrogen, as efficiently as possible is combined heat and power (CHP).[39] CHP is a widely applied technology to maximize the simultaneous production of thermal and electrical energy. By integrating the two processes, CHP can be 50% more efficient than the separate generation of thermal and electric energy. CHP can be applied to many technologies and end uses and is well demonstrated in many industrial applications. CHP would be an excellent technology to maximize the efficient use of low-GHG fuels such as RNG or hydrogen-based fuels.

The natural gas infrastructure provides the foundation for these alternative low GHG technologies, with the potential to deliver RNG or hydrogen blends, or with modification, to

[36] Mcf of industrial transportation consumption / 3.413 MMBtu/MWh = MWh of energy. At 80% capacity factor = GW of demand.
[37] https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf
[38] https://www.southerncompany.com/newsroom/2021/feb-2021/hydrogen-r-and-d-effort-to-achieve-net-zero-goals.html
[39] https://www.epa.gov/chp

deliver pure hydrogen. Pipeline technology could also be used to transport CO_2 for sequestration.

5.3 Electricity Use for GAS Business Operations

Upstream emissions from generation of electricity used in GAS' operations are a small part of the overall inventory. There are two approaches to reducing these emissions:

- End use energy efficiency: GAS can reduce its electricity consumption through energy efficiency measures in buildings and other facilities. These measures could include more efficient lighting, building shell improvements, and HVAC improvements including improved operations and controls and installation of more efficient equipment.
- Green power and renewable energy credits: GAS can also purchase electricity from renewable energy generators and/or purchase renewable energy credits to effectively eliminate upstream emissions from its electricity supply.

To the extent that the electric grid decarbonizes over time, these emissions would decline.

5.4 Reduction of Upstream Emissions from Gas Supply

In addition to the emissions from customer use of gas, GAS' indirect emissions include the emissions from the production, gathering, processing, and delivery of natural gas. The emissions include:

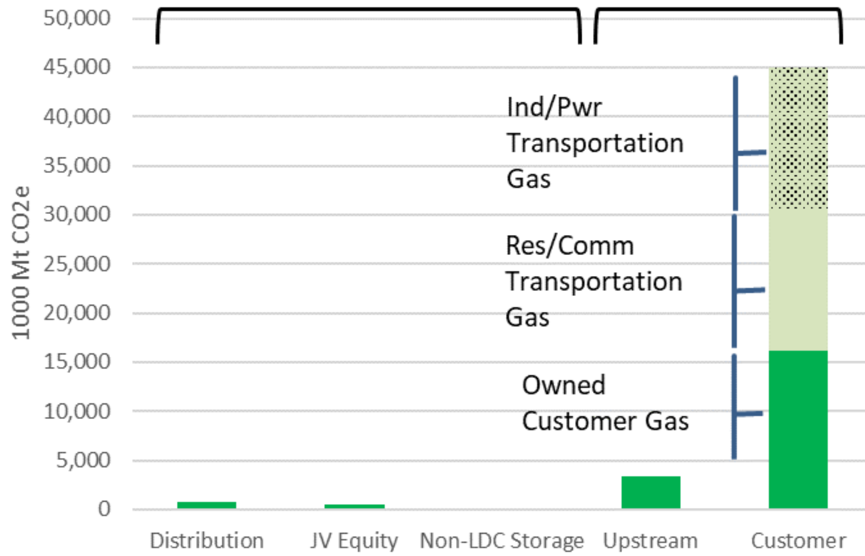
- Fugitive and vented methane emissions along the value chain
- CO_2 from compressors and gas processing operations
- CO_2 that is present in the raw gas and is removed prior to being put into the pipeline.

The U.S. Inventory of Greenhouse Gases and Sinks[40] is the official inventory of U.S. GHG emissions and is updated annually by the EPA. Based on the Inventory and data from the U.S. EIA, ICF estimates that the average upstream emissions of methane and CO_2 are 11.6 kg CO_2e/Mcf at the point of delivery, roughly split evenly between methane and CO_2. (This compares to 54.4 kg CO_2/Mcf from combustion of the gas itself.) Figure 18 shows the direct and indirect emissions including upstream emissions from gas owned and sold by GAS. This does not include the transportation gas that is purchased from other sources by customers and only delivered by GAS because GAS does not know and cannot control the source of that gas.

VNG has already started to reduce these upstream emissions by purchasing 25% of its gas supply from producers who commit to reduce their emissions through improved equipment or operating procedures. The sourcing of gas can also affect the emissions from gas processing since gas from some regions requires less processing than others. Similarly, sourcing gas from regions that are closer to the point of use can reduce the emissions from gas transportation via pipelines.

[40] https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks

Figure 18 - GAS Direct and Indirect Emissions 2019 (1000 Mt CO_2e)



Methane emissions intensity along the gas value chain has been decreasing continuously since 1990. There are companies all along the natural gas value chain who have committed to further reducing their emissions. GAS is part of the ONE Future coalition, which is a gas industry group committed to meeting stringent methane intensity targets. Southern Company Gas is already starting to focus gas procurement on companies that have made commitments consistent with these goals. Other companies subscribe to EPA voluntary emission reduction programs or, like Southern Company, have committed to their own emission reduction targets. Based on the ONE Future targets and other, less formal targets, one could expect an additional 50% reduction in future methane intensity, which would be a 25% reduction in the total upstream emission factor.

In addition to purchasing low-GHG gas, GAS could mitigate these upstream emissions through the displacement of geologic natural gas with lower carbon fuels and the use of carbon offsets, as discussed elsewhere in this report.

6 GHG Mitigation Outside GAS' Operational Scope

While GAS' primary focus is on its own emissions footprint, its expertise and infrastructure could contribute to GHG reductions in other segments of the state economies. While they are not fully developed here, the following examples illustrate potential options for GAS to contribute to reductions outside its operational scope with appropriate regulatory approvals and support.

6.1 Replacement of Oil and Propane in Buildings and Industry

In 2019, consumption of petroleum and propane in the GAS industrial, commercial, and residential sectors contributed 5,661 1000 Mt CO_2 to the Illinois, Georgia, and Tennessee emissions inventories. These fuels have higher GHG emission rates than natural gas and much higher emissions than CO_2-neutral RNG. Replacement of these fuels with natural gas could provide a 1,455 1000 Mt CO_2 reduction in state emissions. Subsequent transition to CO_2-neutral RNG could eliminate this slice of the emissions inventory.

6.2 CNG/RNG Vehicles

As described earlier, CNG and especially compressed RNG vehicles can provide very large reductions in GHGs and conventional pollutants for vehicle applications. The technology is commercially available and widely used for fleets including light duty vehicles, medium duty delivery trucks, and heavy duty vehicles such as transit buses and trash trucks. GAS can continue to help local government and private industry to establish the fueling infrastructure for CNG/RNG vehicles, provide both fuels, and assist with vehicle specification and procurement. These technologies could provide a near-term, cost-effective transition to lower vehicle emissions.

6.3 Capture of RNG-Related Methane

Capturing and/or flaring methane from sources of anaerobic digestion, such as landfills, animal feeding operations, and wastewater treatment plants, has a large GHG benefit, as described earlier. As GAS develops RNG resources, it will capture methane and avoid direct emissions from those other sectors of the state economy.

6.4 Hydrogen for Heavy Transport, Industry, and Power Generation

Renewable hydrogen can provide zero-GHG fuel to thermal processes, either as hydrogen-based gas (P2G), hydrogen blended with natural gas, or pure hydrogen. Southern Company is heavily engaged in the development of hydrogen production and distribution technology and could support the implementation of hydrogen technologies throughout the economy. Hydrogen "islands" for large industrial facilities have already been described in Section 5.2. Hydrogen could also play an important role in power generation. Hydrogen produced from curtailed renewable generation can be used as a form of seasonal energy storage that is more flexible than short-term battery storage to meet electric peaks.

Liquid hydrogen for heavy duty vehicles is an option that could address a part of the transportation sector that may be difficult to address with other technologies such as batteries. Liquid hydrogen fuel stations are in operation in California for heavy duty trucks in commercial operation.

7 Illustrative Decarbonization Pathways

This section describes how the GHG mitigation measures described above can be combined to achieve net zero methane emissions by 2030, net zero direct GHG emissions in 2050, and a significant reduction in customer and other indirect emissions. Several assumptions were included across the analysis for each company.

There are many options for decarbonization of the vehicle fleet, including RNG, hydrogen, electrification, and other alternative fuels. In this case it is assumed that some combination of these measures causes fleet emissions to decline from 2019 levels by:

- 20% in 2030
- 50% in 2040
- 80% in 2050.

The remainder of the fleet emissions are addressed through methane capture offsets from RNG projects.

The following additional assumptions were made to develop the total reduction pathways:

- In-house electricity use – Emissions assumed to decline to zero by 2050 through purchase of green electricity/RECs and decarbonization of the power sector.
- Upstream emissions – Included only for gas that is owned and sold by GAS. Methane intensity reduced by 50% by 2050 through purchase of low-GHG gas. Additional reductions would be possible through purchase of gas from regions with lower processing requirements or closer to end use to reduce pipeline compressor emissions.
- Industrial gas customers – Emissions assumed to be reduced by 15% by 2050 through increased process efficiency and more efficient space and water heating in smaller facilities.
- Power generation gas customers– Consumption decreases by 65% by 2050 due to decarbonization of power sector.
- Residential/commercial customers – Separately modeled to project reductions. See Section 5.

7.1 Direct Emissions

Figure 19 illustrates a potential decarbonization pathway for the GAS methane emissions with a projected 32% reduction in direct methane emissions by 2030, including estimates of system growth. This is achieved through a combination of direct mitigation and improved data and repairs. The pathway achieves net zero methane emissions by 2030, including methane capture offsets. Some methane capture offsets from outside the service territory are required for CGC and VNG.

Figure 19 – Illustrative Methane Reduction Pathway for GAS (1000 Mt CO_2e)

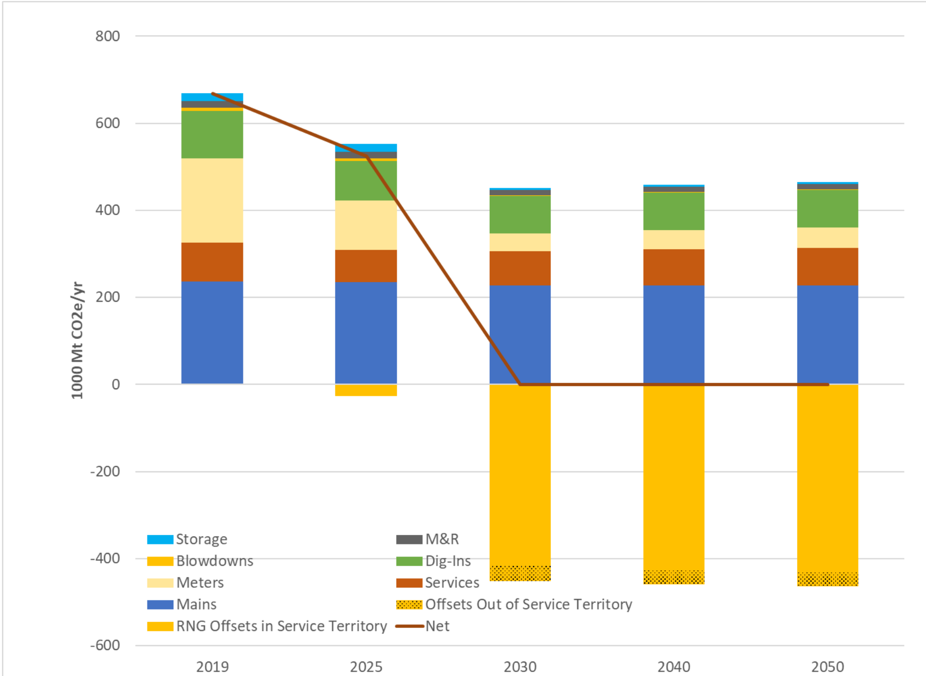
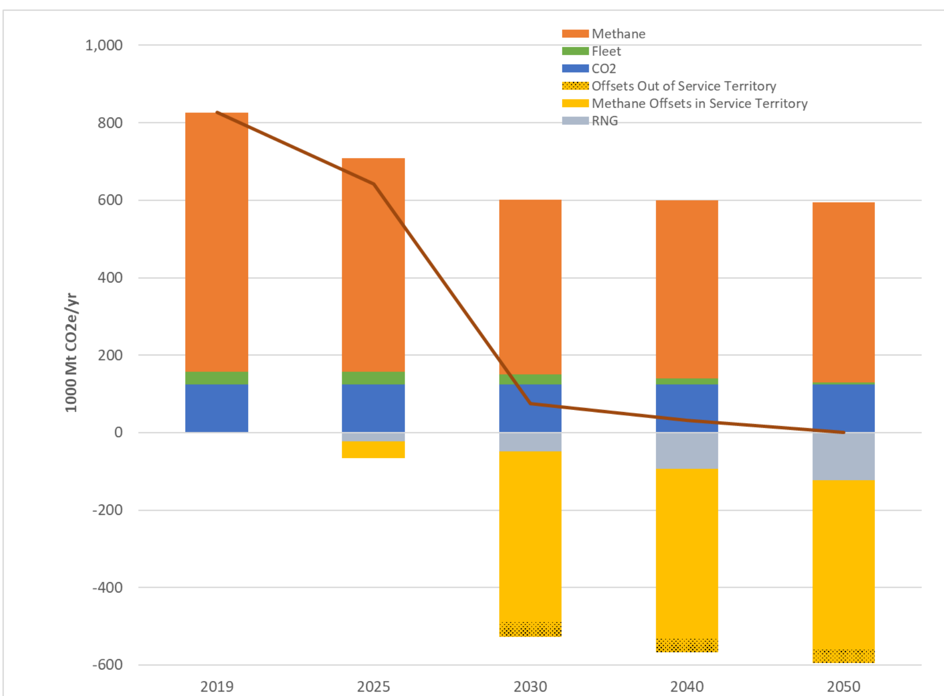


Figure 20 shows an illustrative emissions reduction pathway for GAS direct emissions. It projects a 28% reduction in total direct emissions by 2050, including estimates of system growth. Net zero methane emissions are achieved by 2030 including methane capture offsets. The pathway achieves net zero for all direct emissions by 2050 with RNG/P2G and methane capture offsets. Some methane capture offsets from outside the service territory are required for CGC and VNG.

Figure 20 – Illustrative Direct Emission Reduction Pathway for GAS (1000 Mt CO_2e)



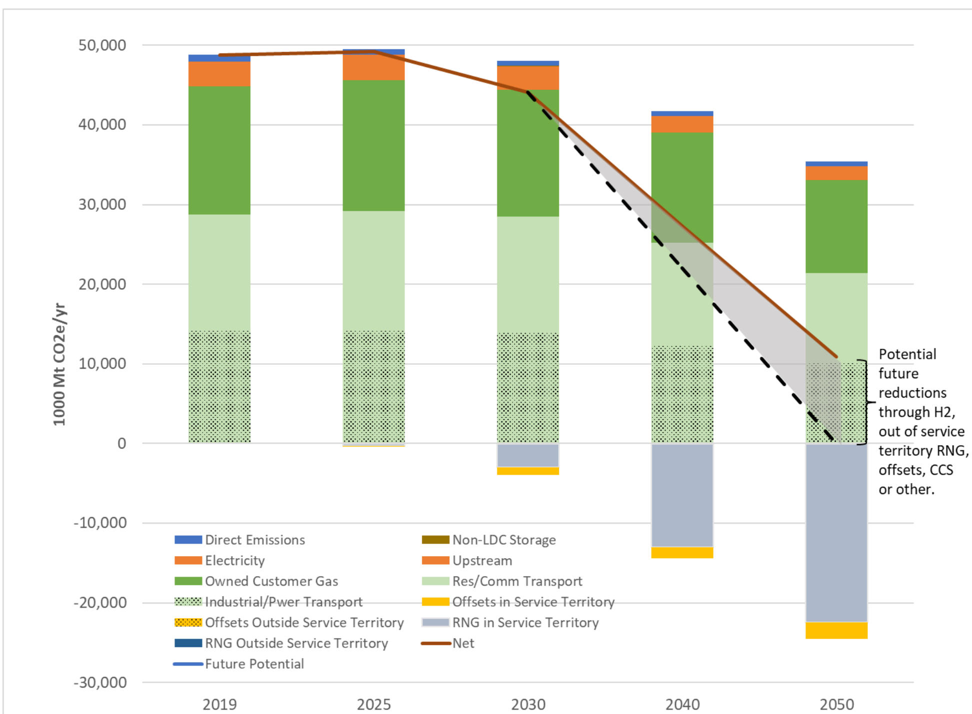
7.2 Indirect Emissions

The GAS indirect GHG emissions include:

- Generation emissions for electricity that is used in-house by GAS.
- Upstream emissions for production, processing, and transportation of gas that is owned and sold by GAS.
- Emissions from customer use of gas.

As discussed earlier and shown in Figure 21, emissions from the customer use of gas are by far the largest source of direct or indirect emissions. As noted above, this pathway analysis includes emissions from all of GAS' customers' use of gas, which is beyond GAS' Scope 3 emissions under applicable GHG protocols, which include only gas owned and sold by GAS. This pathway shows a 78% reduction from 2019 levels by 2050 including those methane capture offsets. The pathway projects that GAS has an opportunity to get to 97% net zero in 2050 for its direct upstream emissions and emissions from gas owned and sold by GAS plus additional reductions for transportation gas at Nicor Gas and Atlanta Gas Light. The GAS utilities could work with their customers and the third party sellers of the gas on its system to support the reduction of the remaining emissions attributable to gas that is sold by third parties, roughly 10,000 Mt CO_2e. Opportunities include hydrogen, RNG, combined heat and power, offsets from other sources, or use of carbon capture and sequestration.

Figure 21 – Illustrative Total Emission Reduction Pathway for GAS (1000 Mt CO_2e)



8 Policy and Regulatory Needs

Decarbonization of the economy will require a broad mix of regulatory and policy drivers to initiate, sustain, and support the process. Decarbonization will have significant costs and other impacts to consumers and to industry and will require mandatory changes of various kinds that will set up competing interests. Careful and realistic analysis will be required to find the most effective, equitable, and least cost path that is in the best interest of customers. Policies should be designed to accommodate change as scientific knowledge, technology options, and other circumstances evolve.

New policies and regulations will be needed to define and structure requirements for reductions and to provide the regulatory support and funding to implement them. Today, there is no national framework or policy to support all of these needs, and there is only a patchwork of state and local frameworks. In many areas, there is only limited data to assess the impacts of different approaches, and no single approach has a clear sight-line for accomplishing all of the broader objectives. In some ways, companies like GAS are in a leadership role in proactively planning for decarbonization. That said, the success of these plans will depend in many ways on the structure and support of public policy.

There is a relatively short list of approaches to reduce GHG emissions:

- Energy efficiency to reduce consumption of fossil fuels
- Shifting to lower-emitting energy sources and technologies
- Reducing emissions of non-CO_2 GHGs through capture or reduced leakage.

The GAS decarbonization pathways include all three of these options. As regulated utilities, the GAS LDC's ability to implement them depends on approval and support from policymakers, the relevant utility regulators, and other stakeholders for energy efficiency programs, methane reduction, and offsetting, RNG and hydrogen development, and other options.

There are many complexities to these deliberations. Utility regulation has historically focused on providing safe and reliable service at the lowest price to consumers with relatively limited explicit consideration of environmental impacts. On the other hand, state and federal environmental regulators have not historically considered the details of utility ratemaking and cost recovery when setting emission standards. More recently, cities have started to establish environment-related regulations (e.g., gas hook-up bans) without coordination with either environmental or utility regulators. In addition, policies established within one city can affect customers across a wide geographic region that have not participated in the decision. Successful decarbonization that minimizes consumer cost impacts will require coordination between local, state, and federal regulators and legislators, and between regulators and utilities. In addition, regulators and legislators will need to ensure that incentives to develop and implement new technologies and new approaches are sufficient to drive desired activity, as cost effectively as possible for customers.

The key decarbonization options on the GAS pathway (efficiency, new technology, lower emission sources, reduced/non-CO_2 fuels) are the same ones that will be needed from the electricity sector and therefore would optimally be addressed across the board by utility regulators.

- Environmental benefits need to be better recognized through incentives and other mechanisms. Policymakers will need to define the basis for prioritization of environmental measures, for example the $/tonne cost of emission reduction. In addition, with lower energy consumption through measures like increased efficiency, consideration should be given to impacts of fixed costs on different customer segments.
- It is also important to consider a broad economy-wide view of the impacts of policies. For example, an evaluation of the emissions associated with certain efforts needs to include off-site as well as on-site emissions. Electrification-focused policy reduces on-site emissions but can increase total emissions if the emissions from generation are not included in the analysis. While efficient electrification is an important tool for longer term energy goals, mandatory single-focused electrification policies could also have significant implications for energy demand and associated infrastructure, affordability, and reliability considerations.
- Gas and electricity utilities can procure lower-emission energy (e.g., renewable electricity, RNG, or certified lower emission natural gas) but these may be higher cost than higher emitting conventional resources. It will be important for policymakers and regulators to consider the value of these resources to customers and support appropriate structures for the companies to provide these resources to customers. For example, RNG today is more expensive than conventional natural gas, but in the scenarios modeled here, is a less expensive decarbonization pathway than policy-driven mandatory electrification and is much lower-emitting than the existing electricity grid in most locations. In addition, RNG can be used in existing customer equipment whereas policy-driven electrification would require consumers to purchase new equipment. Focusing purely on the cost of RNG compared to conventional natural gas would miss these other important considerations.
- In some cases, the local utility does not supply the energy commodity but only provides delivery services. Customers contract separately with energy providers for the energy commodity. Regulators and utilities need to work together to find ways to promote low-emissions energy sources to these customers.
- Investments will be required to develop and bring to market new technologies that will be needed to meet decarbonization objectives. These technologies may include hydrogen, direct air carbon capture, carbon capture and storage, battery storage, fuel cells, and other fundamentally new and innovative technologies, but should also include more efficient natural gas and electric heat pumps, innovative approaches to building shell improvements, and other less revolutionary technologies. For many of these technologies, there is not currently a market incentive to invest in the technologies since they are unlikely to be economic in the current market structure. Allowing utilities and others to invest and recover costs in new technologies would support technology development. Legislators and regulators will need to work together to develop the structures needed to support a market for the best of these technologies. A Carbon Innovation Fund is one example of such a policy.
- There will be crossover between electric and gas technologies and opportunities for each to serve the role they are best positioned for and to support a more integrated and

optimized pathway to emission reduction. Policymakers will need to consider how to balance opportunities for both electric and gas utilities.

A successful, cost-effective decarbonization program requires a cooperative, integrated pathway across sectors, energy sources, and levels of government. Development of low/no-GHG gaseous fuels like RNG and hydrogen is very feasible but requires appropriate support.

Decarbonization will require the involvement of a wide range of policymakers. In addition to local, state, and federal regulators, legislators, and executive branches, other kinds of regulators will be critical. Building codes will be important in setting efficiency standards and ensuring fuel choice (i.e., fuel bans/limits could have a counterproductive impact on a more broad, comprehensive economy-wide approach that ensures that all sectors can contribute to decarbonization efforts and pathways). Fire codes will affect the use of alternative fuels, such as hydrogen. Policymakers should consider this broader range of participants in their planning.

9 Conclusions

Southern Company Gas Can Play a Key Role in Supporting Decarbonization Efforts in the States in Which It Operates

Southern Company Gas (GAS) engaged ICF to analyze how it can develop a pathway for decarbonization of its greenhouse gas (GHG) emissions from its operations and also reduce other GHG emissions in the states in which it operates, especially customer emissions from gas consumption. GAS' parent company Southern Company has committed to achieve net zero direct GHG emissions from its enterprise-wide operations by 2050, which is inclusive of the operations of GAS and its four local gas distribution companies:

- Nicor Gas in Illinois
- Atlanta Gas Light in Georgia
- Virginia Natural Gas (VNG) in Virginia
- Chattanooga Gas Company (CGC) in Tennessee

GAS also includes joint venture gas transmission and storage assets in Texas and California. The GHG reduction goals also include an aspirational target of achieving net zero methane emissions at Nicor Gas by 2030. This study presents different emission reduction pathways and strategies through which GAS can contribute to cost-effective reduction of GHG emissions from its own operations, from its customers, and from other segments of the economy in the states, and also provide other benefits to its customers.

GAS specified the following tenets to be included in evaluating options for a decarbonization pathway for each of its utilities and for its overall operations.

- Reduction or offset to operational and owned Scope 1 GHG emissions
- GHG emissions/sustainability more broadly (Scope 2 and Scope 3)
- Alignment with long-term corporate goals
- Timing considerations for implementation
- Alignment with safety goals
- Alignment with reliability and resilience goals
- Operational feasibility and availability
- Other benefits to customers and local community (e.g., economic development)
- Existence/maturity of policy and regulatory pathway.

The analysis found that achievement of the GHG goals listed above is consistent with all of these tenets. The gas-based GHG reduction pathways identified in this analysis, if realized, would achieve the corporate net zero goal and broader sustainability benefits according to the desired timeline. These pathways preserve or enhance system safety, reliability, and resilience goals and can be achieved with technologies that are feasible and available. The pathways offer benefits beyond GHG reduction, including reduction of other pollutants, reduced energy consumption, and economic development within the service territory. While new policies and regulations may be required to enable and support these pathways, they can be addressed within the existing regulatory and policy frameworks.

The natural gas infrastructure also offers the opportunity to incorporate future low-GHG energy sources such as renewable natural gas and hydrogen. This study indicates that decarbonizing the existing natural gas system and improving the efficiency of the end use gas equipment owned by customers could be a faster, less expensive pathway to reducing GHG emissions than policy-driven mandatory electrification policies that would require major restructuring and rebuilding of energy supply infrastructure and broader replacement of customer equipment. Each of these findings is discussed in this report.

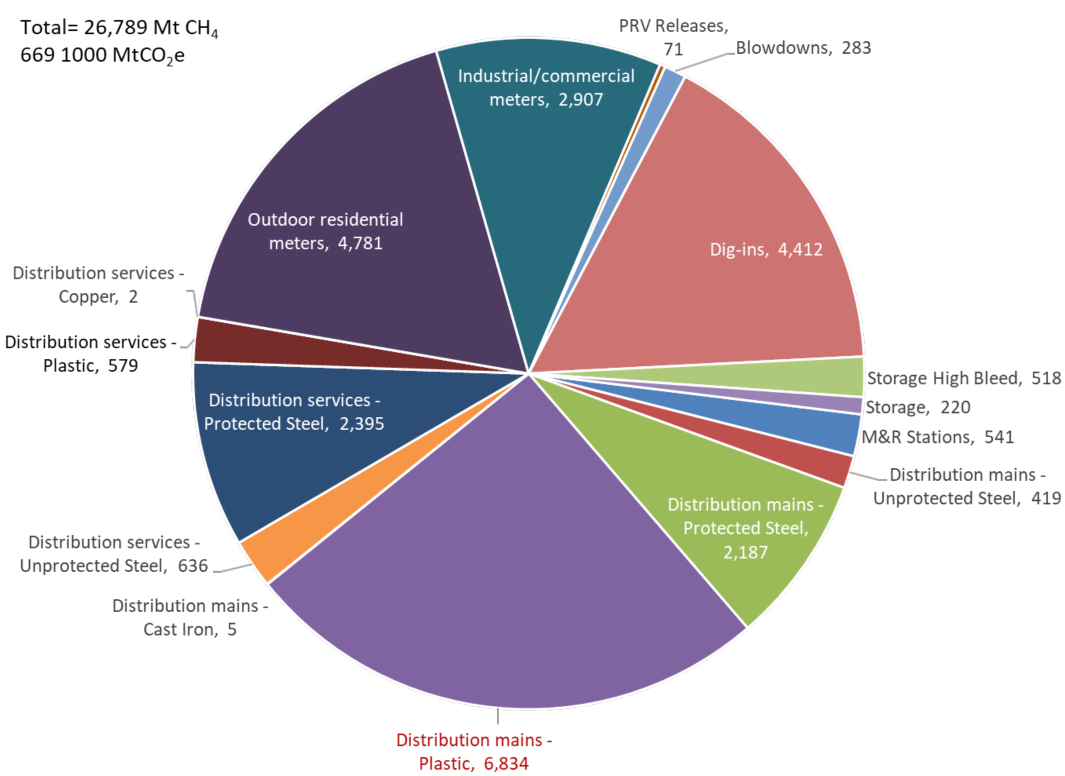
GAS' Direct Emissions are a Very Small Part of the GHG Inventories in the States

GAS' direct GHG emissions from operations include the following:

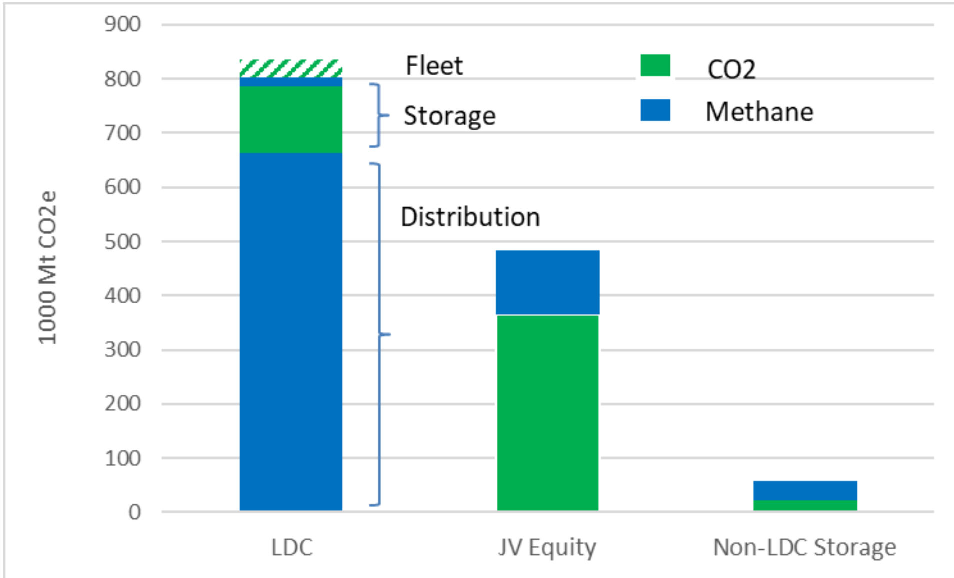
- Fugitive and vented methane emissions from operations at the distribution facilities.
- CO_2 emissions from combustion at distribution operations and fleet vehicles.

Fugitive and vented methane emissions are the largest component of the LDC emissions.

Estimated GAS Methane Emissions – 2019 (Mt CH_4)



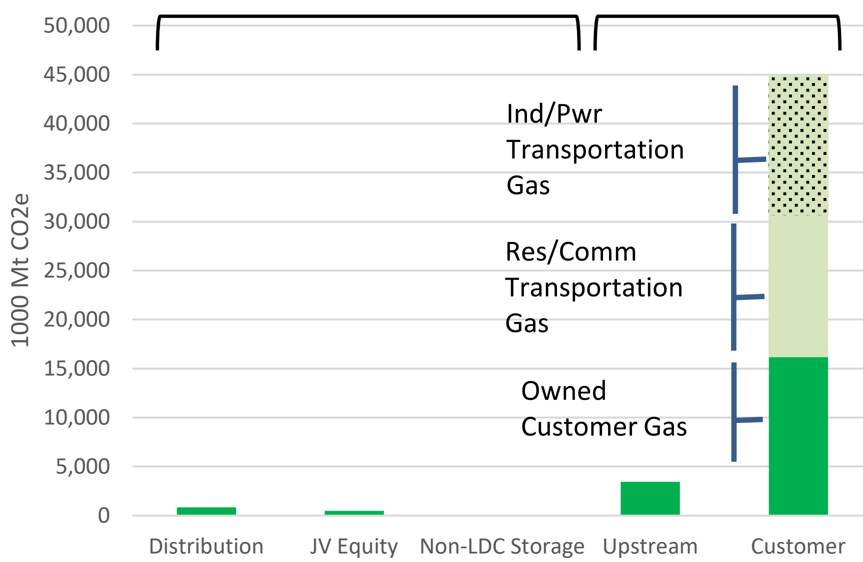
GAS Direct Emissions - 2019 (1000 Mt CO2e)



In addition to the direct emissions from operations, there are also indirect emissions, including the following primarily energy-related sources:

- Emissions from power plants that supply electricity used by GAS.
- Upstream emissions from the production, processing, and transportation of gas that is owned and sold by GAS.
- Emissions from customer use of gas delivered by GAS LDCs.

GAS Direct and Indirect Emissions - 2019 (1000 Mt CO2e)



Emissions related to customer gas use are much larger than any of the other sources, almost 45 million Mt CO_2e based on the total volume of gas delivered to customers as tabulated and reported to the U.S. Energy Information Administration on Form 176.[41] Roughly one third of the customer emissions are from gas owned and sold by GAS versus gas purchased from other sources by customers and delivered by GAS including a large amount of gas delivered to electric generators. The upstream emissions cited in this report only include gas owned and sold by GAS because GAS does not control and cannot track the emissions from gas provided by other entities, consistent with the WRI/WBCSD GHG reporting protocol.

In all cases, the direct emissions from each LDC are less than 1% of the estimated relevant state GHG inventory and range between less than 1% to 5% of the estimated state methane emissions inventory.

Renewable Natural Gas Can Provide Environmental and Economic Benefits to GAS' Customers

Renewable natural gas (RNG) is derived from biomass or other renewable resources and is pipeline-quality gas that is fully interchangeable with conventional natural gas. On a combustion basis, RNG is considered to be a biogenic, CO_2-neutral fuel, for example by the U.S. EPA GHG emissions inventory and Greenhouse Gas Reporting Program and GHG emission trading programs. That is, the CO_2 released from combustion is CO_2 that was previously absorbed by plants from the atmosphere and there is therefore no net increase in atmospheric CO_2. In this project ICF considers three RNG production technologies: anaerobic digestion, thermal gasification, and methane production from hydrogen (for this study, we refer to this resource as "power to gas" or P2G and RNG). ICF prepared three RNG scenarios for RNG supply projections based on a variety of publicly available data sources. Accessing these RNG resources will require project and infrastructure development and regulatory support however RNG can provide a significant contribution to mitigation of direct and indirect emissions, especially for Nicor Gas and Atlanta Gas Light. The RNG potential for CGC and VNG is lower due to their smaller, urban service territory footprint however there is strong RNG potential in those states outside of the service territories.

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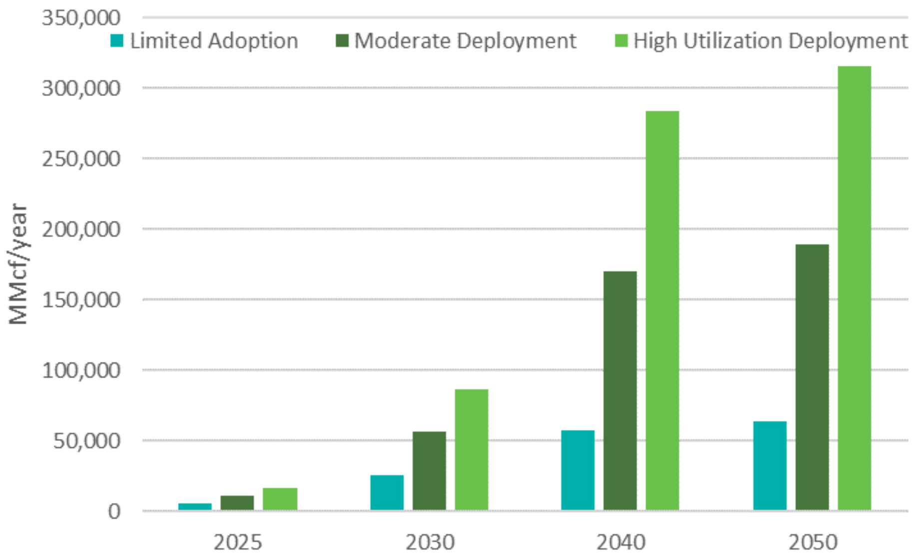
[41] Emissions from customer use of gas are also reported under the EPA GHGRP subpart NN, however the EPA excludes emissions from certain large customers in that report to prevent double counting in its reporting program. On the other hand, according to the current WRI/WBCSD GHG Protocol, GAS' Scope 3 emissions would be limited to the gas owned and sold by GAS, which would be more limited than the subpart NN reported emissions approach, which does not make this distinction. To date, Southern Company has used the subpart NN reported emissions in its reporting to the Carbon Disclosure Project but generally adheres to the WRI/WBCSD GHG Protocol. Southern Company system's GHG emissions are calculated using the equity share approach presented in the WRI/WBCSD GHG Protocol for all of its owned facilities. For purposes of this study, ICF utilized the EIA Form 176 approach to take as expansive a view as possible of all customer emissions associated with gas transported by GAS and identify opportunities to reduce those emissions, but also broke out owned and sold by GAS to provide a better picture of those more limited actual Scope 3 emissions.

Growth Scenarios for Annual RNG Production in GAS Service Territories (MMcf/y)



In addition to providing a CO_2-neutral fuel at the point of use, RNG development provides environmental benefits by converting organic waste into a useful fuel and avoiding the release of these wastes and associated byproducts into the environment. Notably it avoids the release of methane from these wastes directly into the environment as a GHG. It also displaces current use of fossil-based natural gas for uses including thermal use, electricity generation, and use as a transportation fuel. RNG development also creates construction and operation jobs and secondary economic benefits, especially in the agricultural sector, which is an important industry especially in the states in which GAS operates.

When methane is captured from RNG projects, it can sometimes be registered as creditable GHG offsets according to rigorous protocols including the U.N. Clean Development Mechanism, Verra, the American Carbon Registry, and the Climate Action Reserve. These protocols ensure that the offsets are based on real and verifiable reductions that would not have otherwise been achieved. These offsets can be used to mitigate direct emissions such as methane from operations or to offset emissions from combustion.

Another renewable gas option is the use of hydrogen produced through electrolysis with renewable-sourced electricity. The hydrogen produced in this way is a highly flexible energy product that can be:

- Stored as hydrogen and used to generate electricity at a later time using fuel cells or conventional generating technologies,
- Injected as hydrogen into the natural gas system, where it augments the natural gas supply, or;
- Converted to methane and injected into the natural gas system (P2G).

Southern Company is actively engaged in the research and development of new approaches for the production and use of hydrogen. ICF projected the availability of P2G for GAS based on several renewable electricity scenarios, resulting in 27,900 to 69,850 MMcf per year of P2G by 2050.

There is a Pathway for GAS to Achieve Net Zero Direct GHG Emissions

There are available and cost-effective options to reduce the methane emissions that comprise the largest source of GAS' direct emissions. These include direct measures to replace high-emitting pipe, leak detection and repair programs, and more accurate measurement protocols to replace the fixed emission factors currently being used to estimate emissions. The table below shows the potential for a 33% reduction in baseline methane emissions. The remaining methane emissions would be mitigated through the use of methane capture offsets from RNG projects.

Summary of Potential GAS Methane Reductions (Mt CH_4)

	Pipes	Meters	Dig-Ins	Blowdowns	M&R Stations	Storage	LDC Total
Baseline	13,057	7,687	4,412	283	612	702	26,753
Reductions	1,018	6,150	823	212	136	518	8.898
Remaining	12,039	1,537	3,589	71	476	184	17,854

The figure below shows the pathway for mitigation of direct emissions through direct reductions of methane emissions, fleet emissions, and the use of methane capture offsets and RNG to fuel storage compressors. It projects a 28% reduction in total direct emissions by 2050. Net zero methane emissions are achieved by 2030 including methane capture offsets. The pathway achieves net zero for all direct emissions by 2050 with RNG/P2G and methane capture offsets. Some methane capture offsets from outside the service territory are required for CGC and VNG.

Illustrative Direct Emissions Reduction Pathway (1000 Mt CO_2e)

There is a Pathway for GAS to Reduce or Offset its Indirect GHG Emissions

The largest source of indirect emissions was the emissions from customer use of gas. Indirect emissions from upstream methane emissions and CO_2 from combustion were much lower than the customer emissions. The upstream emissions could be addressed through the purchase of gas from entities who commit to reduce their emissions, displacement of geologic natural gas with lower carbon fuels, and through other carbon offset measures. ICF analyzed four scenarios to address decarbonizing customer emissions from the residential and commercial sectors to consider and compare the cost and GHG emissions reduction implications for each scenario to 2050:

- Scenario 1 – Conventional Efficiency Options/RNG - Customers install high efficiency gas furnaces or boilers by 2050 with RNG. Buildings get air sealing and add attic insulation by 2050.
- Scenario 2 – High Efficiency Gas Technology/RNG - Implementation begins in 2025. Natural gas heat pumps start being adopted in 2025. Buildings get deep energy retrofits by 2050 and air sealing/ attic insulation. This pathway also includes displacement of conventional geologic natural gas with RNG based on the RNG resource assessment.
- Scenario 3 – Policy-Driven Mandatory Electrification - All-electric equipment is required for new construction as of 2025. Conversion to electric space and water heating required for replacements starting in 2030. Buildings get deep energy retrofits by 2050 and get air sealing/ attic insulation.
- Scenario 4 – Gas/Electric Hybrid Technology/RNG - Starting in 2023, air-conditioning units get replaced with Air-Source Heat Pumps, forming hybrid-heating systems with the existing gas furnace. Buildings get deep energy retrofits by 2050 and air sealing/ attic insulation. The gas back-up reduces winter peak electric demand.

Under Scenario 3, ICF modeled a scenario of policy-driven mandatory electrification of space and water heating, which is being discussed by some stakeholders. This scenario included achievement of net zero emissions for the electric generating sector by 2050. Under Scenario 4, natural gas was used as a back-up to electric heating systems to reduce winter electric demand peaks, which can have a large effect on electric system infrastructure requirements. The analysis found that the cost of GHG reduction ($/tonne reduced) is about twice as high for the mandatory electrification scenarios as for the gas scenarios.

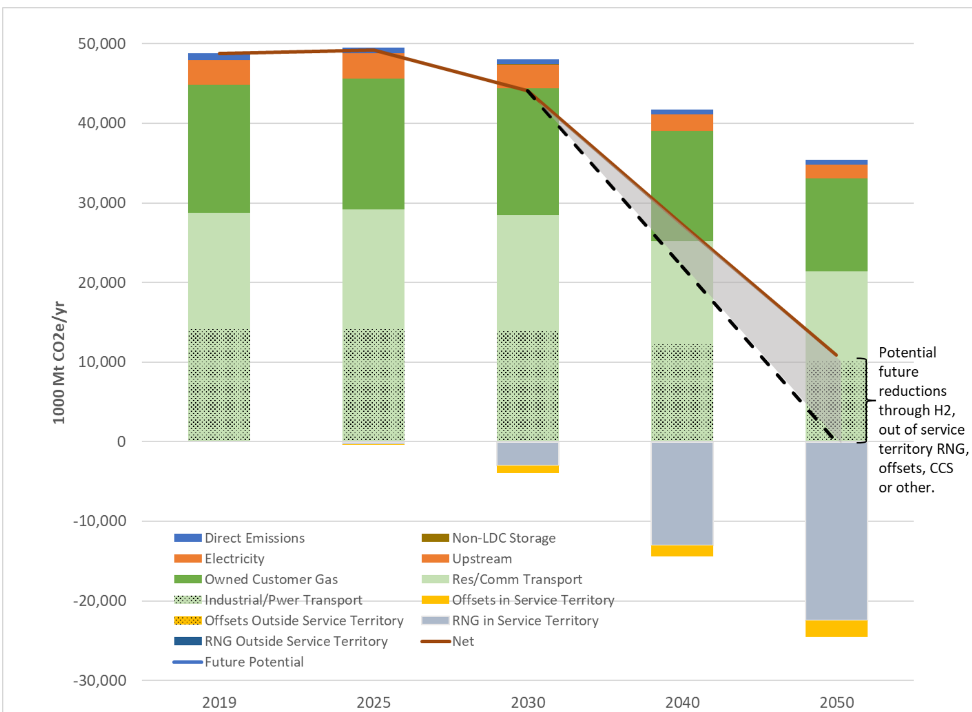
Summary of Customer Scenario Analysis

	2020	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
	Base Year	Conventional Efficiency Options	High Efficiency Gas Technologies	Policy Driven Mandatory Electrification	Gas/Electric Hybrid Approaches
2050 Gas Consumption (Million MMBtu)	580	524.60	419.92	128.54	297.76
2050 Reduction in Gas Consumption vs. 2020 Base Year (%)		-4%	-23%	-76%	-45%
2050 Reduction in Gas Consumption vs. 2050 Reference Case (%)		-18%	-34%	-80%	-53%
2050 GHG Emissions (million tCO_2 / year)	30.8	5.16	0.53	6.82	0.08
2050 Reduction in GHG Emissions vs. 2020 Base Year (%)		-82%	-98%	-76%	-100%

2050 Reduction in GHG Emissions vs. 2050 Reference Case (%)		-85%	-98%	-80%	-100%
Total Costs - NPV of Equipment and 2020-2080 Incremental Energy Costs ($2020 Millions)		$112,020	$129,411	$228,168	$171,321
NPV of 2020 to 2080 GHG Emission Reductions (million tCO_2)		430	495	391	502
Emission Reduction Costs ($/$tCO_2$)		$260	$262	$584	$341

After reviewing the results of the analysis of the four scenarios, ICF developed a reduction pathway, shown in the figure below. This illustrative pathway shows the potential reductions of the total direct and indirect GHG emissions with the direct emission reduction pathway discussed above and the Scenario 2 High Efficiency Gas Technology/RNG results for the residential and commercial sectors.

Illustrative Total Emissions Reduction Pathway (1000 Mt CO_2e)



In addition to the actions for the residential/commercial sector the pathway also assumes energy efficiency improvements and RNG use for the industrial and fleet sectors. As expected, the customer emissions were the largest share of the emissions. This pathway analysis includes emissions from all of GAS' customers' use of gas, which is beyond GAS' Scope 3 emissions under applicable GHG protocols, which only include gas owned and sold by GAS. This pathway shows a 78% reduction from 2019 levels by 2050 including those methane capture offsets. The pathway projects that GAS can achieve net zero in 2050 for 97% of direct and upstream emissions and emissions from gas owned and sold by GAS plus additional reductions for transportation gas at Nicor Gas and Atlanta Gas Light. The GAS utilities could work with their customers and the third party sellers of the gas on its system to support the reduction of the remaining emissions attributable to gas that is sold by third parties, roughly 10 MMt CO_2e. Opportunities include hydrogen, RNG, combined heat and power, offsets from other sources, or use of carbon capture and sequestration.

The Natural Gas Pathways Offer Additional Consumer Benefits

These pathways emphasize energy efficiency, which reduces consumer costs and energy consumption. These pathways also make use of the extensive, reliable, and resilient natural gas energy system that is already in place.

The Natural Gas Pathways Are Projected to be More Cost-Effective Than the Modeled Mandatory Electrification Scenario

The combination of energy-efficient building measures, high efficiency gas heating equipment, and RNG could provide greater GHG reductions for residential and commercial customers at a lower cost to customers resulting in a cost of reduction ($/tonne CO_2e), roughly half that of the policy-driven, mandatory electrification scenario modeled here.

This is true even assuming a rapid, deep electric grid decarbonization scenario leading to net zero grid emissions by 2050. If the electric grid is not decarbonized as fully or as quickly, the emission reductions would be reduced. The replacement of the natural gas energy supply with electricity would require major development of electric generating, transmission, and distribution infrastructure at a time when the electric grid is also decarbonizing, which could have implications for electricity cost, reliability, and resiliency.

Regulatory and Policy Actions Will be Necessary to Support this Transition

Regardless of how decarbonization is achieved, it will require regulatory and policy actions to enable and support it. Decarbonization will result in changes to the energy economy and changes to the energy cost structure. Consistent with their current mission, regulators will need to ensure that costs are equitably distributed between customer classes and that low-income customers are not unfairly burdened.

New Technologies Will Continue to Play a Role and Should be Enabled Through Flexible Policy Approaches

While the pathways defined here achieve the desired goals, there will certainly be new technologies developed over the next 30 years that will assist in meeting the goals. Plans and programs should be flexible enough to incorporate these technologies as they come along. Allowing for multiple future pathways, technology flexibility, and customer choice is more likely to result in cost-effective and efficient emission reductions than fixed, mandatory technology requirements. The emission reduction approach that will best meet the needs of the states and their citizens is likely to change over time and should be able to adapt to future regulatory structures, market developments, consumer needs, and technology developments.

10 Nicor Gas

This section provides information for Nicor Gas in addition to the overview provided in the main body of the report.

10.1 Nicor Gas Overview

Nicor Gas is the largest natural gas LDC in Illinois, serving over 2.2 million customers and delivering 44% of gas delivered in the state. Nicor Gas also operates natural gas storage facilities that can store large amounts of gas to provide peak demand deliveries during the coldest part of the winter. For example, during the "Polar Vortex" of January 30-31, 2019, Nicor Gas delivered a total of 8.9 billion cubic feet (Bcf) with a record 4.9 Bcf in one day on January 30.[42]

Residential customers make up 92% of the customers and most of them purchase the gas commodity from Nicor Gas. Many of the residential transportation-only customers are larger customers, such as large multifamily buildings. Residential customers in general are smaller consumers on an Mcf/customer basis, accounting for only 50% of total deliveries. A much smaller number of commercial and industrial consumers consume roughly 25% each of deliveries. Large commercial and industrial customers purchase gas directly from suppliers or marketers and are the largest share of deliveries in those categories. About one third of the industrial customers consume 93% of the industrial gas deliveries, for which the LDC provides transportation only. This could be important if Nicor Gas offers alternative low GHG fuels, such as RNG or hydrogen to its sales customers. Although Nicor Gas has a role to play in supporting the deployment of these alternative GHG fuels and promoting the development of RNG projects, these efforts will require partnership among Nicor Gas, the suppliers, and their transportation customers.

Table 25 - Nicor Gas Sales and Deliveries - 2019

		Residential	Commercial	Industrial	Electric	Total
Sales	Customers	1,836,633	109,264	12,174	42	1,958,113
	Consumption (Mcf)	212,834,858	43,557,187	8,458,813	2,911	264,853,769
	Mcf/Customer	116	399	695	69	1,279
Transportation	Customers	228,177	43,440	6,136	15	277,768
	Consumption (Mcf)	31,057,815	80,039,572	110,785,819	3,094,677	224,977,883
	Mcf/Customer	136	1,843	18,055	206,312	226,345
Total	Customers	2,064,810	152,704	18,310	57	2,235,881
	Consumption (Mcf)	243,892,673	123,596,759	119,244,632	3,097,588	489,831,652

Data source: EIA Form 176

The industrial transportation customers are much larger customers, with large base load process needs. The average per customer consumption for industrial transportation customers is about 30 times higher than for the industrial sales customers. The total energy demand for the

[42] Nicor Gas analysis

large industrial customers is estimated to be equivalent to almost 5 GW of electric demand.[43] In the commercial sector, about one third of the customers consume about 65% of commercial deliveries, with per customer consumption more than three times higher than commercial sales customers.

In the northern Illinois region where Nicor Gas operates, natural gas supplies 75% of the natural gas and electricity energy needs of Nicor Gas customers. Nicor Gas delivers almost 5 times more energy in the form of natural gas per residential customer than those customers receive from electricity providers, according to data from the Energy Information Administration and the Illinois Commerce Commission. Overall, Nicor Gas customers consume 3 times more energy per customer in the form of natural gas than electricity.

Figure 22 – Nicor Gas Customer Distribution – 2019 (1000)

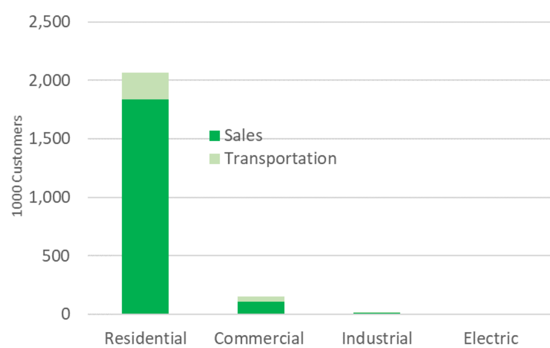
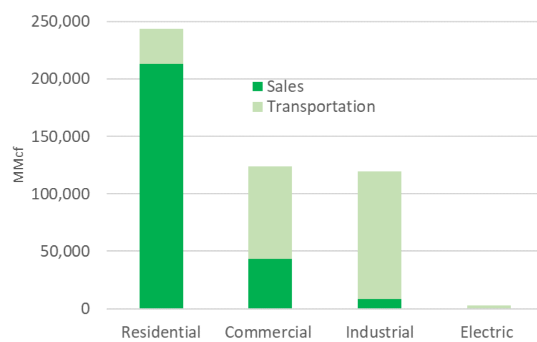


Figure 23 - Nicor Delivery Distribution – 2019 (MMcf)



10.2 Nicor Gas Emissions

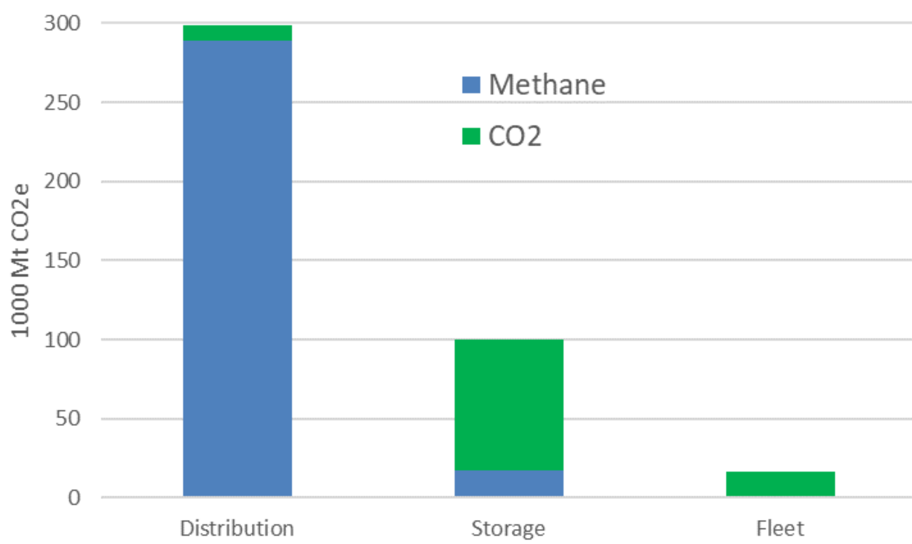
Nicor Gas' direct GHG emissions from operations include the following:

- Fugitive and vented methane emissions from operations at the distribution and natural gas storage facilities.
- CO_2 emissions from combustion at distribution operations, storage operations, and from fleet vehicles.

The direct emissions totaled 416 1000 Mt CO_2 equivalent in 2019. The largest component was methane emissions from the distribution operations. That said, Nicor Gas estimates that it has reduced annual methane emissions from its distribution system from 1998 to 2018 by over 45% — even as the system grew by approximately 20%. Nicor Gas' methane emissions were 5% of the estimated Illinois methane emissions. The second largest component was emissions from the storage facilities, mostly CO_2 from gas-fired compressors. The CO_2 emissions from vehicle fleets was the third, much smaller piece.

[43] 110,785,819 Mcf of industrial transportation consumption = 33,433,751 MWh of energy. At 80% capacity factor = 4.8 GW of demand.

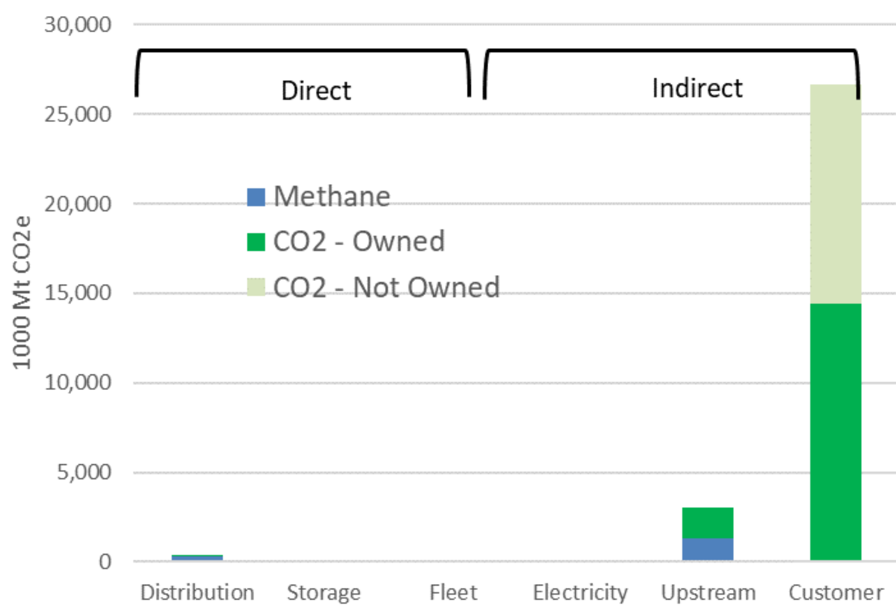
Figure 24 - Nicor Gas Direct GHG Emissions - 2019 (1000 Mt CO2e)



Data Source: Nicor Gas

Figure 25 and Table 26 show that Nicor Gas indirect emissions related to customer gas use are much larger than any of the other sources. Roughly half the customer emissions are from gas owned and sold by Nicor Gas versus gas purchased from other sources by customers. The upstream emissions shown include only gas owned and sold by Nicor Gas because Nicor Gas does not control and cannot track the emissions from gas provided by other entities.

Figure 25 – Nicor Gas Direct and Indirect GHG Emissions - 2019 (1000 Mt CO2e)



Data Source: Nicor Gas

Table 26 - Nicor Gas Direct and Indirect GHG Emissions - 2019 (1000 Mt CO2e)

	Direct Emissions			Indirect Emissions			Total
	Distribution	Storage	Fleet	Electricity	Upstream	Customer	
Methane	289.1	17.5			1,350.7		**1,657.3**
Owned CO2	9.6	82.6	16.8	9.8	1,721.5	14,407.7	**16,248.0**
Not Owned CO2						12,238.4	**12,238.5**
Total	**298.7**	**100.1**	**16.8**	**9.8**	**3,072.2**	**26,646.1**	**30,143.8**

Table 27 summarizes the ICF estimate of Illinois GHG emissions. Comparing these results (in million tonnes) with the Nicor Gas data in Table 26 (1000 tonnes) and Table 27 (MMt), Nicor Gas' direct emissions in 2019 had the following characteristics:

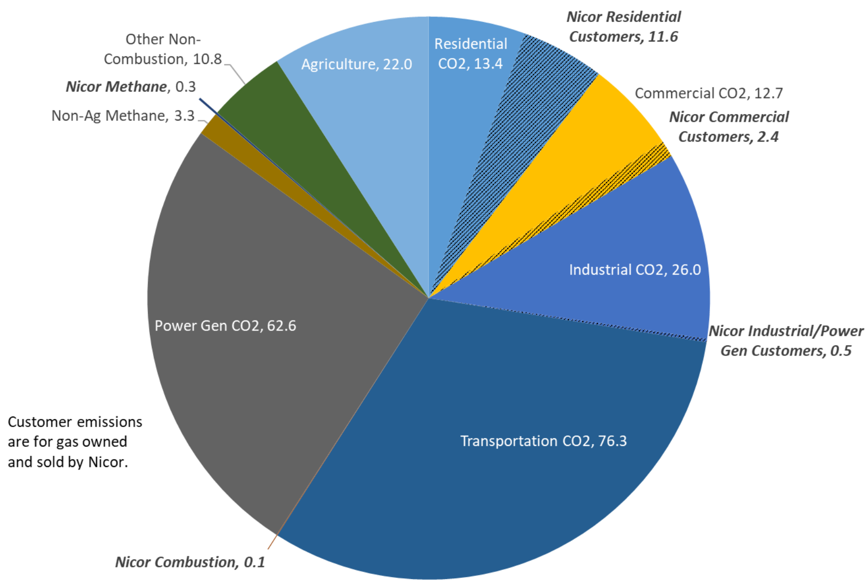
- Nicor Gas' total direct GHG emissions were less than 0.2% of the estimated total Illinois GHG emissions.
- Nicor Gas' methane emissions were 5% of estimated total Illinois methane emissions.
- The total Nicor emissions including gas owned and sold by Nicor Gas were 7% of the estimated total Illinois GHG emissions.

Table 27 - Estimated Illinois GHG Emissions – 2019 (MMt CO_2e)

Source	MMt CO_2e	Data Source
CO_2 From Combustion		
Residential	25.0	EIA
Commercial	15.1	EIA
Industrial	26.4	EIA
Transportation	76.3	EIA
Power Gen	62.6	EIA
Total Combustion	205.5	
Non-Combustion		
Landfill Methane	2.6	GHGRP
Coal Mine Methane	2.2	GHGRP
Gas System Methane	0.6	GHGRP
Methane - Other	0.5	GHGRP
Other Non-CO_2	1.9	GHGRP
Non-Combustion CO_2	8.9	GHGRP
Manure Management	2.3	EPA SIT
Enteric Fermentation	2.2	EPA SIT
Soil Management	16.9	EPA SIT
Other Ag	0.6	EPA SIT
Subtotal Non-Combustion	38.7	
Total	244.1	

Figure 26 shows the Nicor Gas emissions in the context of the estimated state emissions.

Figure 26 - Estimated Illinois and Nicor Gas GHG Emissions - 2019 (MMt CO_2e)



10.3 RNG for Nicor Gas

The following table summarizes the maximum RNG potential for each biomass-based feedstock and production technology by geography of interest, reported in million cubic feet (MMcf). The RNG potential includes different variables for each feedstock, but ultimately reflects the most favorable options available, such as the highest biomass price and the utilization of all feedstocks at all facilities.

Table 12 - Technical Potential for Nicor Gas RNG Production by Feedstock (MMcf/yr)

RNG Feedstock	Nicor Gas	Rest of IL	Total
Animal Manure	15,737	19,189	34,951
Food Waste	3,121	685	3,806
Landfill Gas	46,050	14,456	60,506
Water Resource Recovery Facilities	4,808	690	5,498
Anaerobic Digestion Sub-Total	*69,716*	*35,019*	*104,736*
Agricultural Residue	146,060	84,197	230,257
Energy Crops	286,362	410,366	696,729
Forestry & Forest Product Residue	2,190	1,297	3,487
Municipal Solid Waste	27,524	6,040	33,564
Thermal Gasification Sub-Total	*462,136*	*501,900*	*964,036*
Total	*531,853*	*536,919*	*1,068,772*

ICF developed economic supply curves for three separate scenarios for each feedstock. The

RNG potential included in the supply curves is based on an assessment of resource availability. In a competitive market, that resource availability is a function of multiple factors, including but not limited to demand, feedstock costs, technological development, accessibility to pipeline connections, and the policies in place that might support RNG project development. ICF assessed the RNG resource potential of the different feedstocks that could be realized, given the necessary market considerations (without explicitly defining what those are).

Table 28 - Projected Annual RNG Production in Nicor Gas Service Territory by 2050 (MMcf/yr)

RNG Feedstock		Scenario		
		Limited Adoption	Moderate Deployment	High Utilization Deployment
Anaerobic Digestion	Animal Manure	3,250	5,838	7,819
	Food Waste	1,398	2,060	2,499
	LFG	6,215	11,794	17,332
	WRRFs	2,091	3,260	4,202
Thermal Gasification	Agricultural Residue	490	56,639	69,063
	Energy Crops	7,298	30,731	102,718
	Forestry and Forest Product Residue	657	1,095	1,533
	Municipal Solid Waste	7,923	10,564	13,762
Total		29,322	121,981	218,928

Figure 27 - Growth Scenarios for Annual RNG Production in Nicor Gas Service Territory (MMcf/yr)

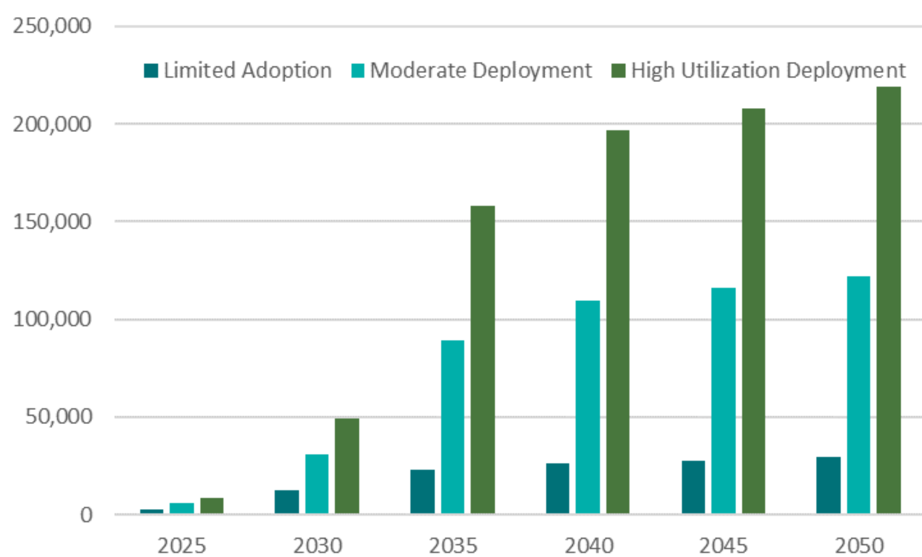


Figure 28 - P2G Production Scenarios for Nicor Gas (MMcf/yr)

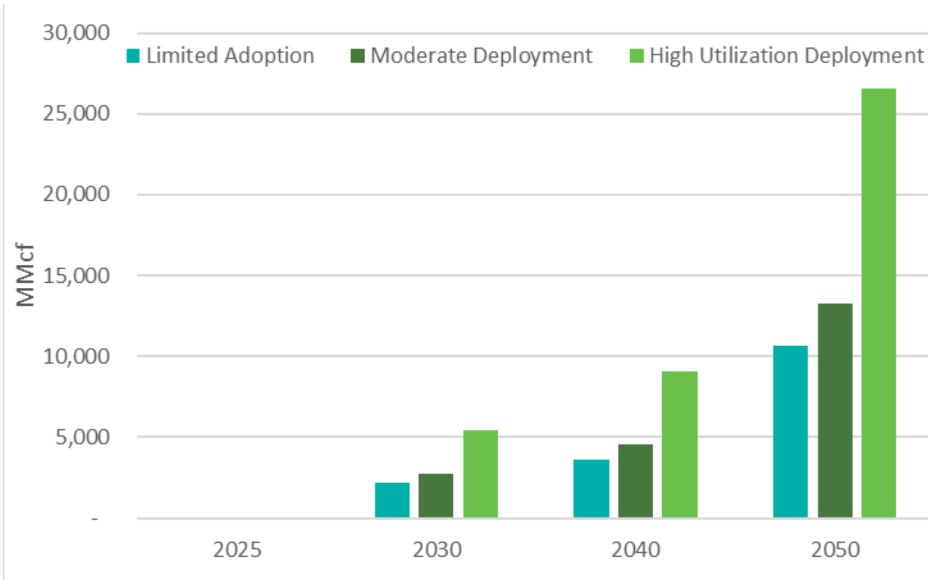


Figure 29 and Figure 30 present the RNG/P2G potential in the context of the Nicor Gas deliveries. The left two bars show the gas deliveries in 2019 and potential deliveries in 2050 with the implementation of energy efficiency measures as in Scenario 2 discussed in Section 5.1.The three bars on the right side show the total amount of RNG/P2G and gas equivalent of offsets that are projected to be available in 2030, 2040, and 2050 in each of the three growth RNG scenarios. This does not include consumption of these resources for other uses than customer demand (i.e., offsetting direct emissions), which is addressed in the pathway analysis in Section 7.

Figure 29 – RNG Potential vs Nicor Gas Deliveries by Supply Case (MMcf/yr)

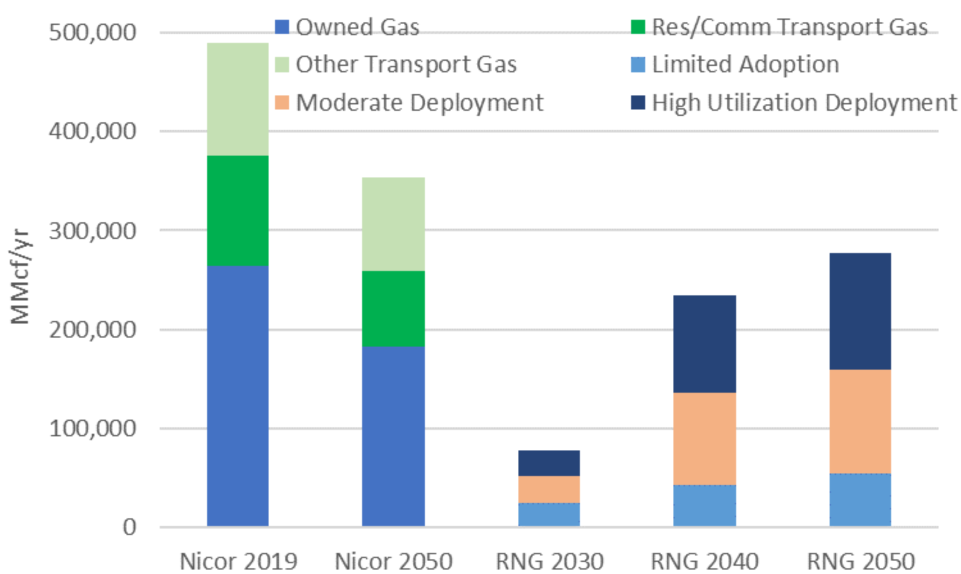


Figure 30 – RNG Potential vs Nicor Gas Deliveries by Supply Type (MMcf/yr)

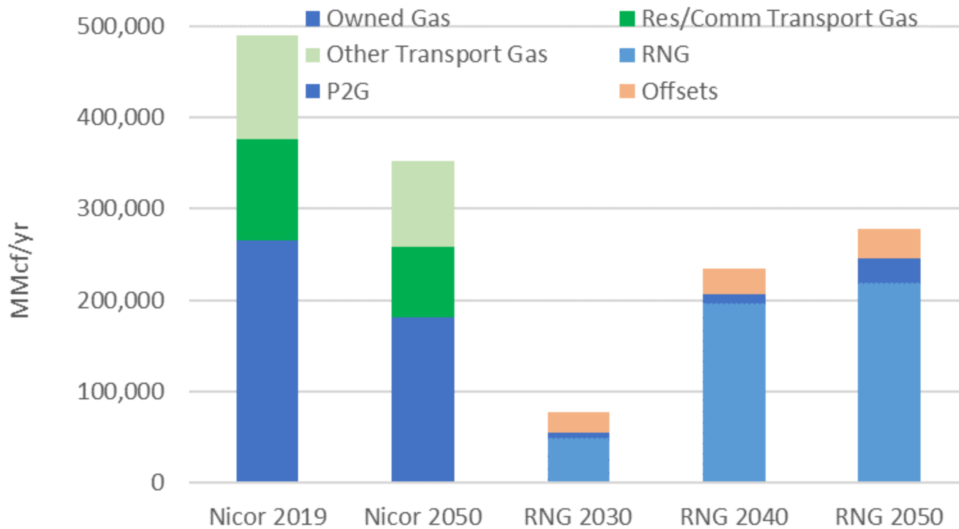


Figure 31 shows a comparison of selected decarbonization measures across various key studies for specific abatement measures that are likely to be required for economy-wide decarbonization in the 2050 timeframe, including natural gas demand side management (DSM),[44] RNG (from this study), carbon capture and storage (CCS),[45] direct air capture (whereby CO_2 is captured directly from the air and a concentrated stream is sequestered or used for beneficial purposes),[46] battery electric trucks (including fuel cell drivetrains),[47] and policy-driven electrification of certain end uses (including buildings and in the industrial sectors).[48,49]

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[44] See Con Edison's Smart Usage Rewards program (https://www.coned.com/en/save-money/rebates-incentives-tax-credits/smart-usage-rewards-for-reducing-gas-demand) and National Grid's Demand Response Pilot program (https://www.nationalgridus.com/GDR).

[45] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.).

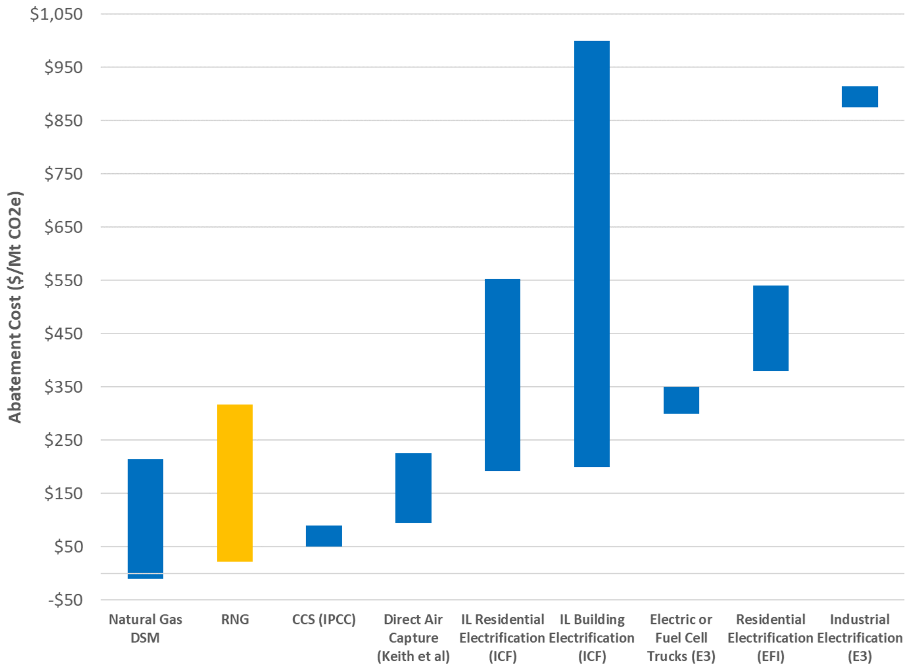
[46] Keith, DW; Holmes, G; St Angelo D; Heidel, K; A Process for Capturing CO_2 from the Atmosphere, *Joule*, 2 (8), p1573-1594. https://doi.org/10.1016/j.joule.2018.05.006

[47] E3, 2018. Deep Decarbonization in a High Renewables Future, https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization

[48] Energy Futures Initiative (EFI), 2019. Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California, https://energyfuturesinitiative.org/efi-reports.

[49] ICF, 2018, Implications of Policy-Driven Residential Electrification, https://www.aga.org/globalassets/research--insights/reports/AGA_Study_On_Residential_Electrification.

Figure 31 - GHG Abatement Costs, Selected Measures ($/Mt CO_2e)



10.4 Direct Emission Reductions

Figure 32 shows the breakdown of the methane emissions, which totaled 12,262 Mt CH_4 in 2019 or, weighted by the GWP, 306.6 1000 Mt CO_2e. Three components accounted for 90% of the emissions. Customer meters comprised 35%, distribution mains and services comprised 39%, and dig-ins (damage to mains and services from construction) comprised 16%. Nicor Gas estimates that it has reduced annual methane emissions from its distribution system from 1998 to 2018 by over 45% — even as the system grew by approximately 20%.

Figure 32 - Nicor Gas Methane Emissions 2019 (Mt CH_4)

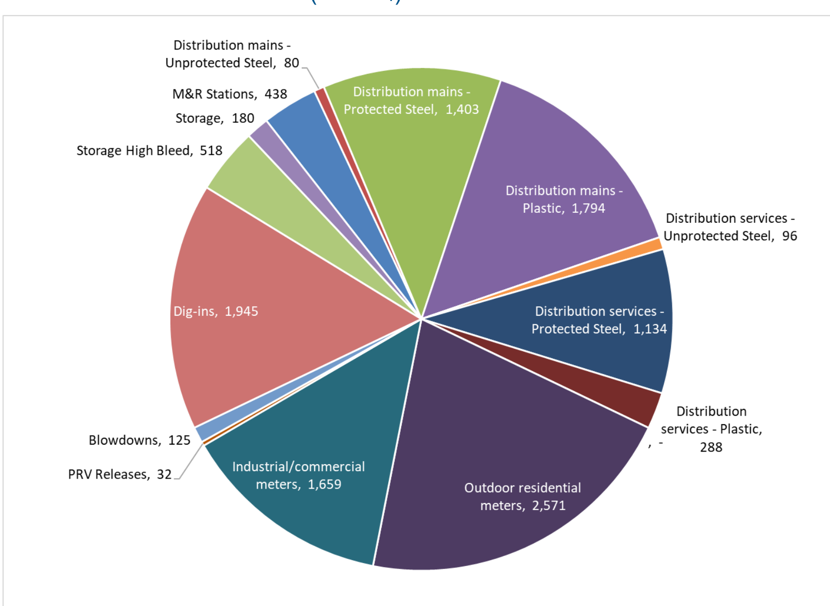


Table 29 summarizes the potential reduction in estimated methane emissions for the Nicor Gas LDC and storage facilities. The largest reductions are from enhanced LDAR and monitoring of meters, followed by more accurate calculation of dig-in emissions and reduction of pneumatic device emissions at the storage facilities. The total potential reduction is 40%.

Table 29 - Summary of Potential Methane Reductions for Nicor Gas (Mt CH_4)

	Pipes	Meters	Dig-Ins	Blowdowns	M&R Stations	LDC Total	Storage	Grand Total
Baseline	4,796	4,230	1,945	125	470	1,564	698	12,262
Reductions	169	3,384	668	94	109	4,423	518	4,941
Remaining	4,627	846	1,277	31	361	7,141	180	7,321

10.5 Indirect Emission Reductions

This section provides details on the customer modeling for Nicor Gas. The measures are installed gradually through requirements for new construction and stock turnover in existing buildings as shown in. The implementation of gas heat pumps is more gradual due to the newness of the technology.

Table 30 - Technology Penetration in Gas Scenarios

Scenario 1 – Conventional Efficiency Options/RNG	Scenario 2 – High Efficiency Gas Technology/RNG
Implementation begins in 2025 Almost 80% of customers install high efficiency gas furnaces or boilers by 2050 35% of buildings get air sealing and add attic insulation by 2050	Implementation begins in 2025 Natural gas heat pumps start being adopted in 2025 and reach 57% of single family homes, 30% of multi-family, 42% of commercial buildings by 2050 31% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic insulation

Table 31 summarizes the results of the gas scenarios for Nicor Gas. The two scenarios are compared to a reference case in which gas demand continues to grow from current levels by about 15% through 2050 based on growth forecasts from the U.S. EIA Annual Energy Outlook.[50] The scenarios result in a 22% reduction in direct fuel use in 2050 for Scenario 1 and 39% in Scenario 2 compared to the reference case. In addition to the increased efficiency, the scenarios substitute RNG for conventional natural gas. In Scenario 1, efficiency plus RNG was able to reduce customer CO_2 emissions by 87%. In Scenario 2, efficiency plus RNG fully replaces conventional gas, resulting in a 100% reduction in CO_2 emissions from these customers. The table also shows the net present value cost of equipment installations through 2050 and incremental customer energy costs through 2080. (Energy costs through 2080 are included in order to include the operating costs of equipment installed in 2050 over a reasonable

[50] https://www.eia.gov/outlooks/aeo/

time period using that equipment.) The net present value of emission reductions through 2080 is then calculated in order to calculate an emission reduction cost in \$/tonne CO_2 reduced. The emission reduction cost is \$259/tonne CO_2 reduced for Scenario 1 and \$252/tonne for Scenario 2 across all residential and commercial customers.

Table 31 - Summary of Nicor Gas Scenario Results

	2020 Base Year	Scenario 1 Conventional Efficiency Options/RNG	Scenario 2 High Efficiency Gas Technologies/ RNG
2050 Gas Consumption (Million MMBtu)	387	338	265
2050 Reduction in Gas Consumption vs. 2020 Base Year (%)	-	-13%	-32%
2050 Reduction in Gas Consumption vs. 2050 Reference Case (%)	-	-22%	-39%
2050 GHG Emissions (MMt CO_2 / year)	20.5	3	0.00
2050 Reduction in GHG Emissions vs. 2020 Base Year (%)	-	-86%	-100%
2050 Reduction in GHG Emissions vs. 2050 Reference Case (%)	-	-87%	-100%
Total Costs - NPV of Equipment and 2020-2080 Incremental Energy Costs (\$2020 Millions)	-	74,220	82,583
NPV of GHG Emission Reductions (MMt CO_2)	-	286	328
Emission Reduction Costs (\$/tCO_2)	-	\$259	\$252

The figures below provide additional context for the annual impacts for residential and commercial Nicor Gas customers out to 2050, which drive the results showcased in the Scenario Summary above. Figure 33 shows the overall reduction in Nicor Gas residential and commercial natural gas demand out to 2050.

Figure 33 – Annual Gas Demand for Nicor Gas (Trillion Btu)

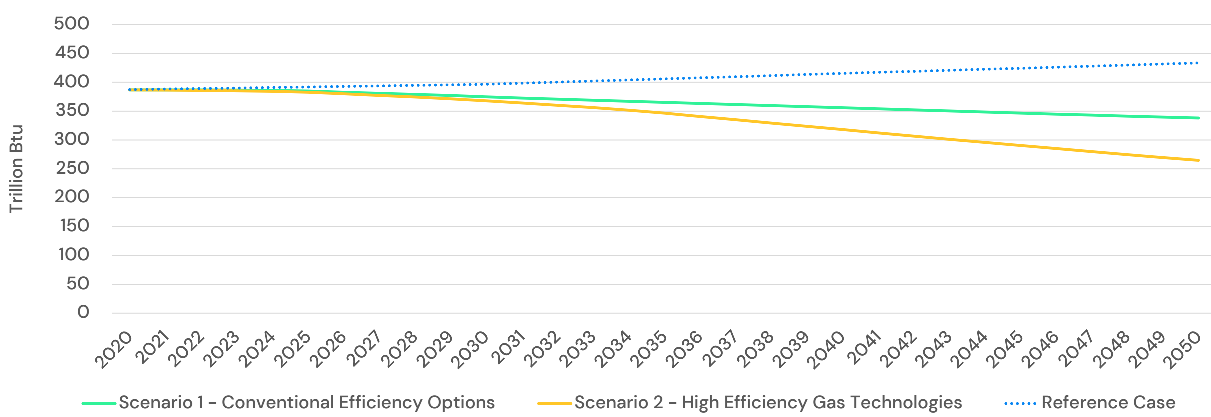


Figure 34 shows the total increase in energy costs from the gas scenarios, including the incremental upfront costs to install higher efficiency equipment and better insulate homes, changes in the energy costs to customers (based on reference case natural gas rates and the reduction in natural gas consumption), and incremental costs to purchase decarbonized gases (RNG and P2G). Figure 35 provides additional context on the make-up of those changes in customer energy costs.

Figure 34 – Total Annual Costs - Equipment Installations and Incremental Energy Costs) ($Millions)

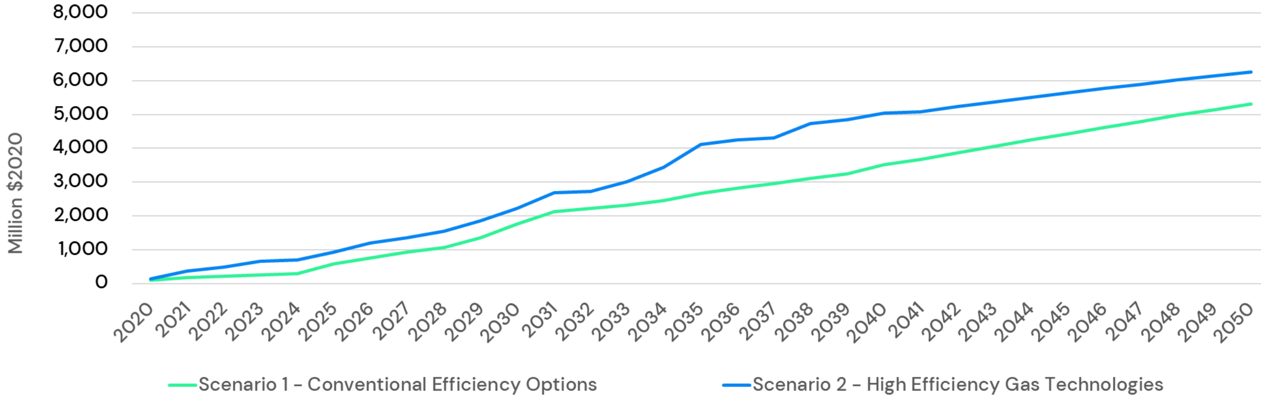


Figure 35 – Incremental Nicor Gas Annual Energy Costs ($Millions)

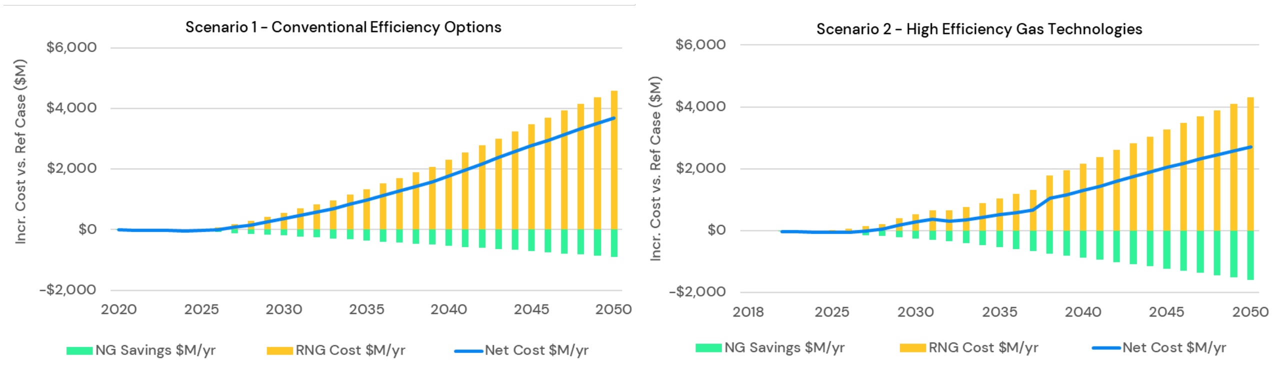


Figure 36 shows the emission reduction pathways for both of these scenarios. If RNG was not included in these scenarios, and no other changes were made, the GHG emission reductions would be reduced, matching gas demand reductions from Figure 33, but the emission reductions costs ($/t$CO_2$) would also be lower.

Figure 36 – CO_2 Emissions from Natural Gas for Nicor Gas (Million tCO_2)

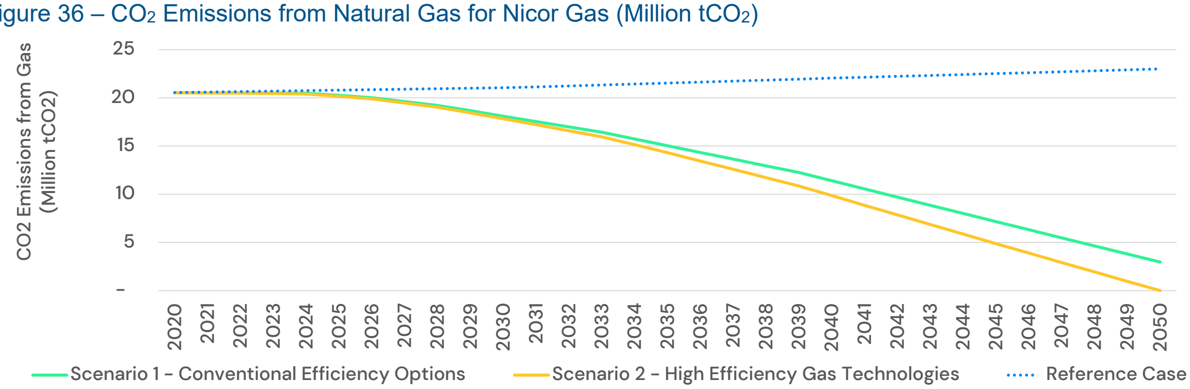


Table 32 summarizes the technology penetration assumptions for the electrification scenarios. Mandatory policies are assumed to require electrification for all new construction starting in 2025 and for all replacement/retrofits starting in 2030. The all-electric space heating share of single family homes reaches 92% of single family homes by 2050.

Table 32 - Technology Penetration in Electricity Scenarios for Nicor Gas

Scenario 3 – Policy-Driven Mandatory Electrification	Scenario 4 – Gas/Electric Hybrid Technology/RNG
Mandatory all-electric for new construction as of 2025. Mandatory conversion to electric space and water heating starting in 2030 when replacing equipment. All-electric space heating share reaches 92% in single family homes and 88% in commercial by 2050. Mix of ASHPs and electric resistance. 31% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic insulation	Starting in 2023 air-conditioning units get replaced with Air-Source Heat Pumps, forming hybrid-heating systems with the existing gas furnace. By 2050 hybrid heating reaches 78% of single family homes and 76% of commercial. 31% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic insulation

Table 33 summarizes the results of the Nicor Gas electrification scenarios. The two scenarios are compared to a reference case in which gas demand continues to grow from current levels by about 15% through 2050 based on growth forecasts from the U.S. EIA Annual Energy Outlook. The scenarios result in a reduction of direct fuel use in 2050 by 84% for Scenario 3 and 59% in Scenario 4, compared to the reference case. In addition to the electrification and efficiency improvements, Scenario 4 also meets the remaining gas demand with RNG (no RNG is used in Scenario 3). In Scenario 3, mandatory electrification and energy efficiency do not fully eliminate natural gas demand by 2050 because not all gas heating equipment is replaced and there are some non-heating/water heating gas applications that remain, resulting in an 84% reduction in natural gas CO_2 emissions from residential and commercial customers. In Scenario 4, targeted electrification, energy efficiency, plus RNG reduce customer CO_2 emissions by 100%. The table also shows the net present value of equipment installations through 2050 and incremental customer energy costs through 2080. (Energy costs through 2080 are included in order to include the operating costs of equipment installed in 2050 over a reasonable period of time using that equipment.)

Table 33 - Summary of Electric Scenario Results for Nicor Gas

	2020 Base Year	Scenario 3 Policy-Driven Mandatory Electrification	Scenario 4 Hybrid Gas/Electric Technologies
2050 Gas Consumption (Million MMBtu)	387	68	179
2050 Reduction in Gas Consumption vs. 2020 Base Year (%)	-	-82%	-54%
2050 Reduction in Gas Consumption vs. 2050 Reference Case (%)	-	-84%	-59%
2050 GHG Emissions (MMt CO_2 / year)	20.5	4	0.00
2050 Reduction in GHG Emissions vs. 2020 Base Year (%)	-	-82%	-100%
2050 Reduction in GHG Emissions vs. 2050 Reference Case (%)	-	-84%	-100%

Total Costs - NPV of Equipment and 2020-2080 Incremental Energy Costs ($2020 Millions)	-	$150,733	$106,958
NPV of GHG Emission Reductions (MMt CO_2)	-	268	329
Emission Reduction Costs ($/t$CO_2$)	-	$561	$325

Customer energy costs include changes in:

- Natural gas costs (based on reference case natural gas rates and the reduction in natural gas consumption),
- Costs for the additional electricity needed for electrified equipment (based on reference case electricity rates and the cost adders shown in Table 21),
- Cost increases on baseline electricity consumption (original customer electric load, less efficiency improvements, not including the newly electrified portion) for Nicor Gas customers from the increase in electric rates assumed to be driven by the changes in these scenarios (based on the cost adders shown in Table 21, but showing just the cost increase incremental to changes that would occur for scenario 1 and 2 based on their respective adders; for example scenario 3 is based on impact for Nicor Gas customers if electric rates went up 4 cents/kWh, while scenario 4 is based on a rate increase of 0.5 cents/kWh), and
- Incremental costs to purchase decarbonized gases (RNG and P2G for Scenario 4 only).

The net present value of emission reductions through 2080 is then calculated in order to calculate an emission reduction cost in $/tonne CO_2 reduced. The emission reduction cost is $561/tonne CO_2 reduced for Scenario 3 and $325/tonne for Scenario 4, across all residential and commercial customers (there are differences in costs by customer types, with higher costs for commercial buildings). The targeted electrification with greater fuel flexibility assumed in Scenario 4 has a lower cost than the broader electrification requirement assumed in Scenario 3, as well as the value of continuing to leverage the gas distribution system to meet peak winter heating energy demand on the coldest days of the year. That said, it could have significant impacts on gas system operations and cost that are not included in this model, as discussed above.

The figures below provide additional context on the annual impacts for residential and commercial Nicor Gas customers out to 2050, which drive the results summarized in the Scenario Summary. Figure 37 shows the overall reduction in Nicor Gas residential and commercial natural gas demand out to 2050.

Figure 37 – Nicor Gas Annual Gas Demand (Trillion Btu)

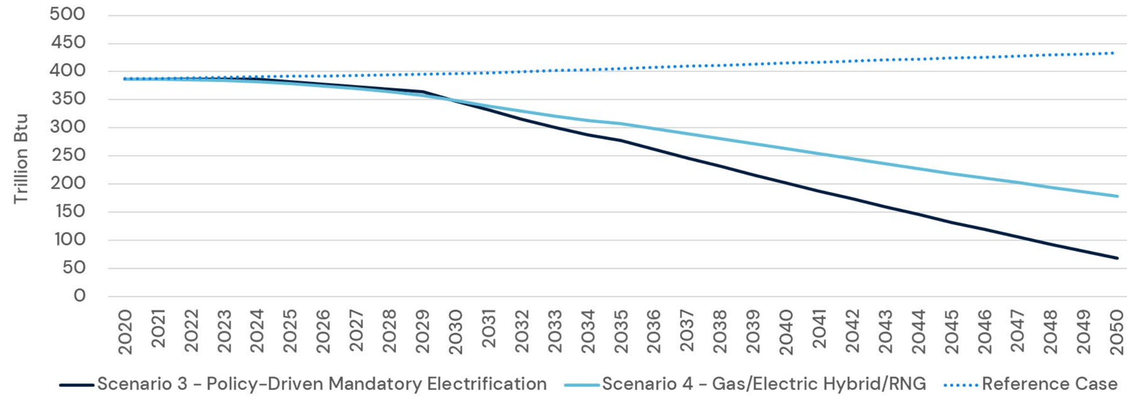


Figure 38 shows the total increase in energy costs from the electrification scenarios, including the incremental upfront costs to install higher efficiency equipment, electric equipment, or better insulate homes, and changes in the energy costs to customers.

Figure 38 – Total Annual Costs – Nicor Gas Equipment Installations and Incremental Energy Costs ($Millions)

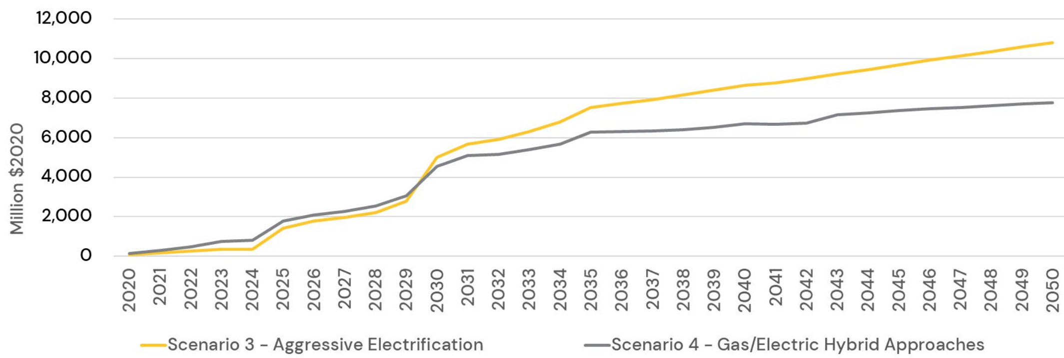


Figure 39 provides additional detail on the make-up of the changes in customer energy costs discussed above.

Figure 39 – Nicor Gas Incremental Annual Energy Costs ($Millions)

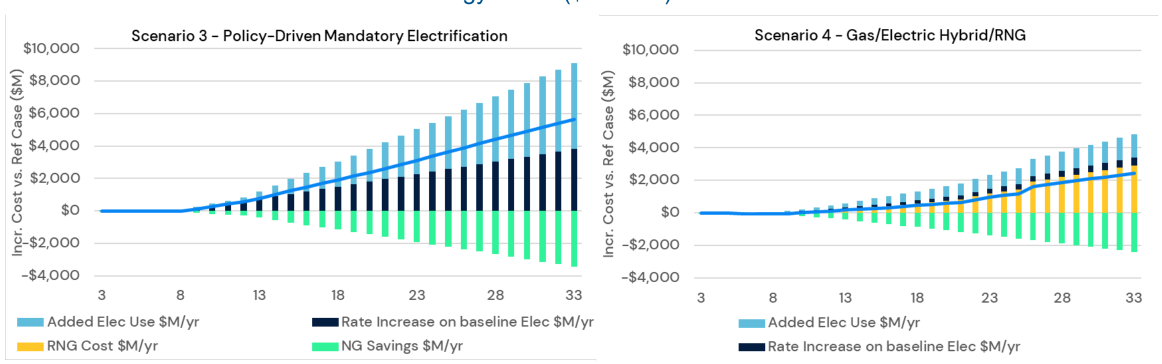


Figure 40 shows the emission reduction pathways for both of these scenarios. The use of RNG in the Gas/Electric Hybrid Scenario results in larger emission reductions by 2050 than the Policy-Driven Mandatory Electrification Scenario analyzed here.

Figure 40 – CO_2 Emissions from Natural Gas for Nicor Gas ($MMtCO_2$)

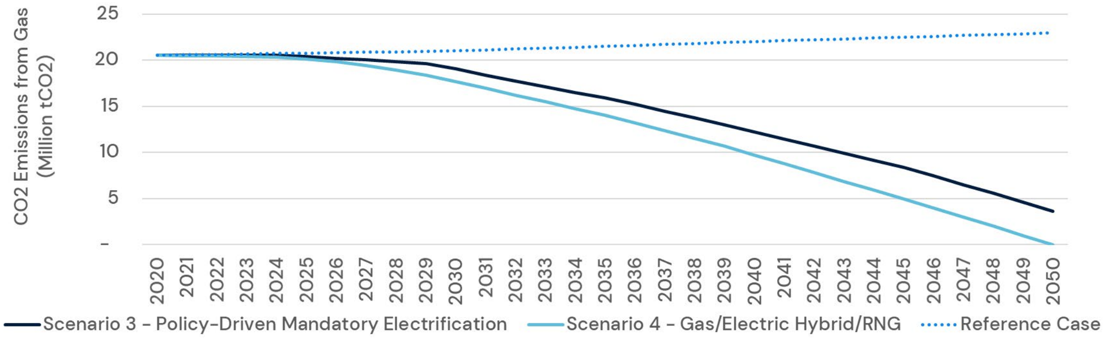


Table 34Table 35 summarizes the results of the residential and commercial customer scenario modeling. The High Efficiency Gas Technology/RNG (Scenario 2) achieves the greatest GHG reduction, the lowest consumer cost, and lowest emission reduction cost ($/tonne).

Table 34 - Summary of All Nicor Gas Scenario Results

	2020	Scenario 1	Scenario 2	Scenario 3	Scenario 4
	Base Year	Conventional Efficiency Options/ RNG	High Efficiency Gas Technologies/ RNG	Policy-Driven Mandatory Electrification	Hybrid Gas/Electric Technologies/ RNG
2050 Gas Consumption (Million MMBtu)	387	338	265	68	179
2050 Reduction in Gas Consumption vs. 2020 Base Year (%)	-	-13%	-32%	-82%	-54%
2050 Reduction in Gas Consumption vs. 2050 Reference Case (%)	-	-22%	-39%	-84%	-59%
2050 GHG Emissions (MMt CO_2 / year)	20.5	3	0.00	4	0.00
2050 Reduction in GHG Emissions vs. 2020 Base Year (%)	-	-86%	-100%	-82%	-100%
2050 Reduction in GHG Emissions vs. 2050 Reference Case (%)	-	-87%	-100%	-84%	-100%
Total Costs - NPV of Equipment and 2020-2080 Incremental Energy Costs ($2020 Millions)	-	$74,220	$82,583	$150,733	$106,958
NPV of GHG Emission Reductions (MMt CO_2)	-	286	328	268	329
Emission Reduction Costs ($/t$CO_2$)	-	$259	$252	$561	$325

Figure 41 shows the key results graphically. The Policy-Driven Mandatory Electrification scenario has the highest cost to consumers but the lowest reduction in GHG emissions, resulting in a cost of reduction twice as high in $/tonne GHG reduced as the High Efficiency Gas scenario.

Figure 41 – Nicor Gas Scenario Cost and Reduction Comparison

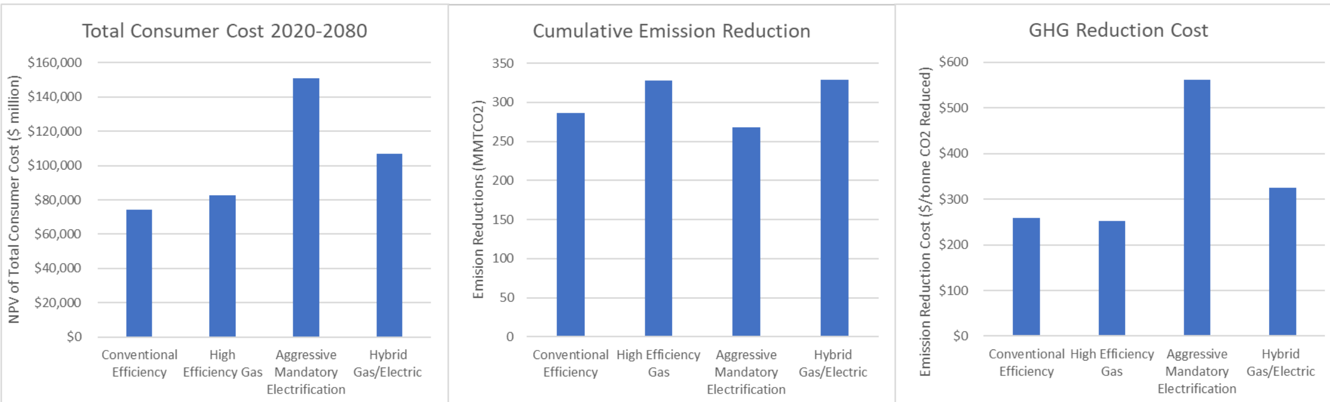


Table 35 shows the emission reduction cost by the various customer segments for new and existing building types. The gas technologies consistently have the lowest cost due primarily to the deep reductions achieved through high efficiency and CO_2-neutral RNG. For scenarios 2 and 3, higher emission reduction costs for new buildings (vs. existing buildings) reflect the cost increase to build 'net-zero ready' buildings with a lower thermal load, while the savings from such measures are only captured out to 2080. Scenario 1 includes more modest building shell improvements for new construction.

Table 35 – Nicor Gas GHG Reduction Cost ($/tonne CO_2e)

Customer type	Vintage	$ Per Metric Ton of CO_2 2020-2080 (Discounted)			
		Scenario 1	Scenario 2	Scenario 3	Scenario 4
Single Family	**All vintages**	**$190**	**$161**	**$197**	**$132**
Single Family	New	$178	$201	$226	$185
Single Family	Existing	$193	$152	$192	$120
Multi-family	**All vintages**	**$249**	**$234**	**$550**	**$217**
Multi-family	New	$265	$267	$538	$240
Multi-family	Existing	$245	$226	$553	$212
Small Commercial	**All vintages**	**$374**	**$397**	**$1,002**	**$504**
Small Commercial	New	$471	$544	$1,179	$611
Small Commercial	Existing	$324	$322	$911	$450
Large Commercial	**All vintages**	**$582**	**$702**	**$3,195**	**$1,830**
Large Commercial	New	$819	$1,042	$3,847	$2,322
Large Commercial	Existing	$449	$512	$2,838	$1,549
Institutional	**All vintages**	**$304**	**$328**	**$1,206**	**$685**
Institutional	New	$325	$395	$1,362	$825
Institutional	Existing	$292	$291	$1,120	$606

10.6 Decarbonization Pathways for Nicor Gas

Figure 42 illustrates a potential decarbonization pathway for the Nicor Gas methane emissions. Baseline methane emissions can be expected to increase as Nicor Gas adds new customers with meters, service lines, mains and with dig-ins, blowdowns, etc. The customer growth rate is as described for the customer emission modeling in Section 5.1, resulting in an increase of 2%

over 2019 in 2030 and 7% over 2019 in 2050. The largest reductions from the baseline emissions are replacement of pipeline and high bleed pneumatic controllers, expanded LDAR, improved quantification of methane emissions from meters, and improved quantification of dig-in emissions. Despite the growth, the mitigation measures result in an estimated 38% reduction in methane emissions by 2030 including estimates of system growth. The remaining methane emissions can be offset with methane capture offsets from RNG projects, resulting in net zero methane emissions in 2030 and continuing through 2050.

Figure 42 – Nicor Gas Methane Emissions Reduction Pathway (1000 Mt CO_2e)

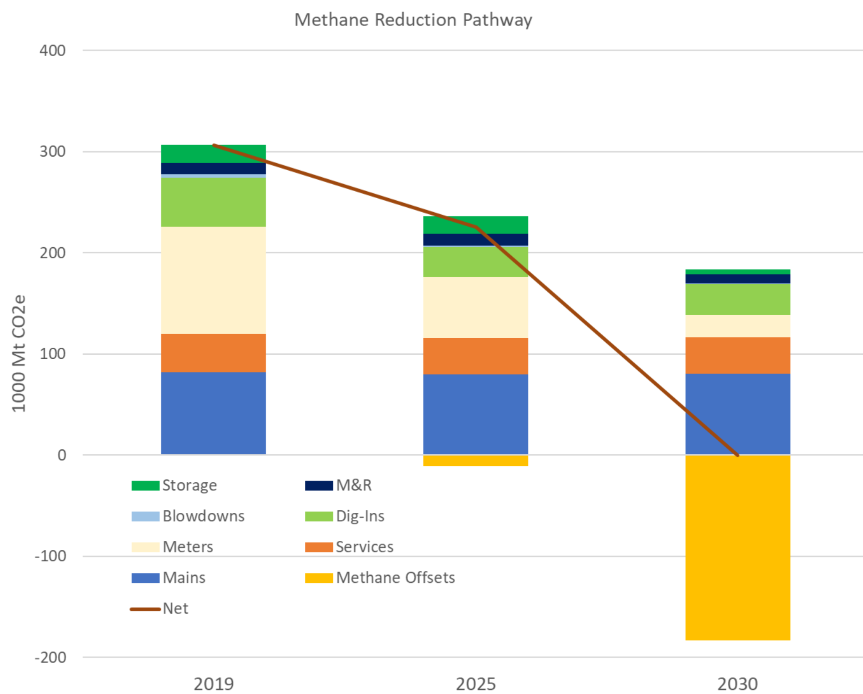
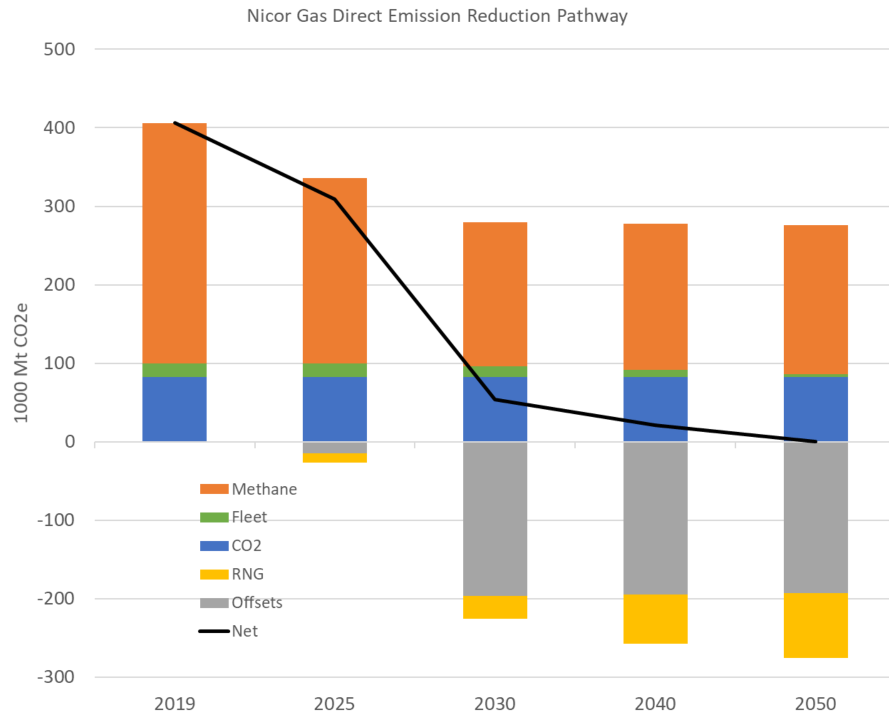


Figure 43 shows the reduction pathway for direct emissions including CO_2 from combustion at storage facilities and fleet emissions. While there are several potential mitigation options for the storage facilities, including electrification for compressors, this pathway assumes that the facilities are fueled with RNG to eliminate CO_2 emissions. That said, electrification for compressors could be considered as a future option depending on operational considerations for the storage facility operation and decarbonization of the electric grid.

Figure 43 shows that methane remains the largest component of direct emissions and methane capture offsets remain an important measure for achieving net zero emissions through 2050 with the addition of RNG to fuel the storage facilities.

Figure 43 - Nicor Gas Direct Emissions Reduction Pathway (1000 Mt CO_2e)



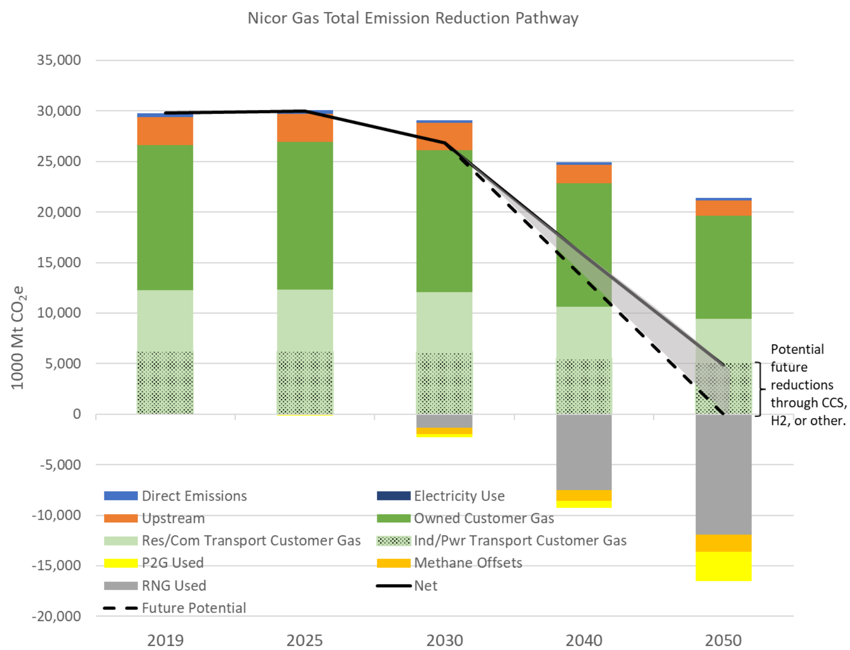
The Nicor Gas indirect GHG emissions include:

- Generation emissions for electricity that is used in-house by Nicor Gas.
- Upstream emissions for production, processing, and transportation of gas that is owned and sold by Nicor Gas.
- Emissions from customer use of gas.

As discussed earlier and shown in Figure 44, emissions from the customer use of gas are by far the largest source of direct or indirect emissions. As noted above, this pathway analysis includes emissions from all of Nicor Gas' customers' use of gas, which is beyond Nicor Gas' Scope 3 emissions under applicable GHG protocols, which only include gas owned and sold by Nicor Gas.

The direct and indirect emissions were projected to be reduced by 28% from 2019 to 2050. Using the High Utilization Deployment estimate of RNG, P2G, and offset availability, Nicor Gas is projected to be net zero in 2050 for 100% of direct emissions, upstream emissions, and combustion emissions from gas owned and sold by Nicor Gas. This results in an 84% estimated reduction in net emissions from 2019 to 2050. The remaining emissions from combustion of transportation gas delivered to Nicor Gas customers could potentially be reduced or offset through opportunities like hydrogen, RNG, combined heat and power, offsets from other sources, or use of carbon capture and sequestration.

Figure 44 - Nicor Gas Total Emission Reduction Pathway (1000 $MtCO_2e$)



11 Atlanta Gas Light

11.1 Atlanta Gas Light Overview

Atlanta Gas Light, part of Southern Company Gas, is the largest natural gas LDC in Georgia, serving over 1.6 million customers in 2019. Atlanta Gas Light delivered 28% of gas delivered in the state and 84% of the gas delivered to residential and commercial customers in 2019. Atlanta Gas Light also operates liquefied natural gas (LNG) storage facilities that can store gas to provide peak demand deliveries during the coldest part of the winter. The importance of this capacity was demonstrated during a cold snap on January 6 and 7, 2014. Both Atlanta Gas Light and Georgia Power recorded their highest demand in recent years on those days. Atlanta Gas Light delivered a peak 1,961,704 MMBtu of gas on January 6[51] – an average equivalent to 24 GW of electricity. This was 40% more than Georgia Power's maximum delivery of 16.8 GW on January 7.[52] That said, Atlanta Gas Light's design capacity – the capacity that it is required to plan for is 28% higher than this peak – equivalent to over 30 GW of peak delivery.

Atlanta Gas Light delivers natural gas to its customers through its pipeline system but all of its customers purchase the gas commodity from third party Marketers or, in the case of some larger customers, directly from a gas producer. This is referred to as "transportation gas" because Atlanta Gas Light provides the local transportation and delivery of the gas but does not take ownership of the gas or sell it to customers. This could be important for the use of alternative low GHG fuels, such as RNG or hydrogen. Although Atlanta Gas Light has a role to play in supporting the deployment of these alternative GHG fuels and promoting the development of RNG projects in the state, these efforts will require partnership among AGL, the Marketers and their customers. Table 36, Figure 45, and Figure 46 summarize the distribution of Atlanta Gas Light customers and deliveries by customer segment.

Figure 45 – Atlanta Gas Light Delivery Distribution – 2019 (MMcf)

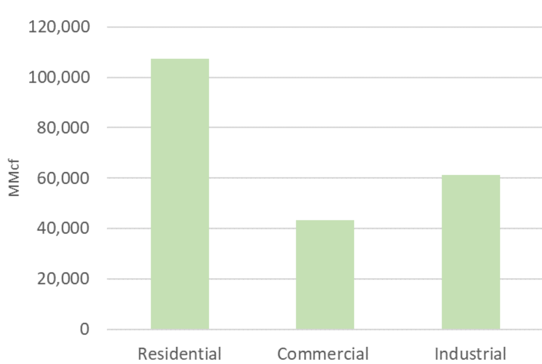
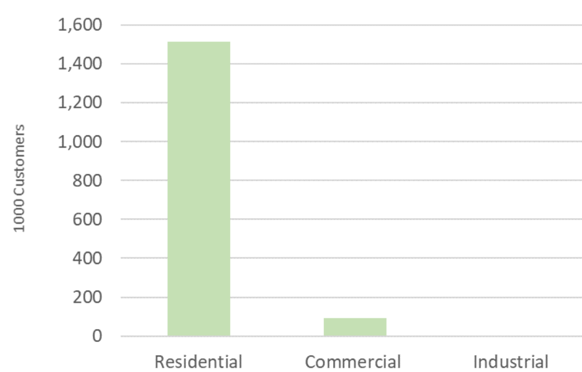


Figure 46 – Atlanta Gas Light Customer Distribution – 2019 (1000)



Data source: EIA Form 176

51 Atlanta Gas Light data

52 https://www.prnewswire.com/news-releases/georgia-power-sets-winter-peak-demand-record-239600941.html

Table 36 – Atlanta Gas Light Gas Deliveries - 2019

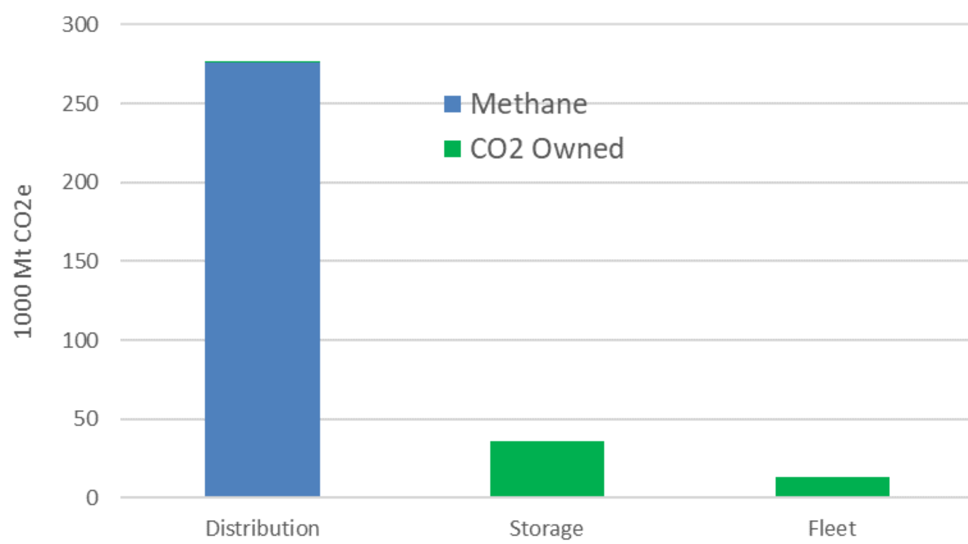
	Residential	Commercial	Industrial	Total
Customers	1,515,379	93,706	1,518	1,610,603
Consumption (Mcf)	107,253,281	43,196,897	61,330,058	211,780,236
Mcf/Customer	71	461	40,402	40,934

Residential customers made up 94% of the customers and about half of the deliveries in 2019. Commercial customers accounted for 6% of the customers but 20% of the deliveries. Industrial customers comprised less than 1% of the customers but 29% of deliveries. There were no power generation customers. The industrial customers are much larger consumers of gas, with large base load process needs.

11.2 Atlanta Gas Light Emissions

Atlanta Gas Light's direct emissions totaled 326 1000 Mt CO_2e in 2019. The largest component was methane emissions from the distribution operations. That said, Atlanta Gas Light estimates that it has reduced annual methane emissions from its distribution system from 1998 to 2018 by approximately 60% — even as the system grew by approximately 25%. The second largest emission component was emissions from the LNG storage facilities, primarily CO_2 from gas-fired compressors and electric generators. CO_2 emissions from vehicle fleets was the third component.

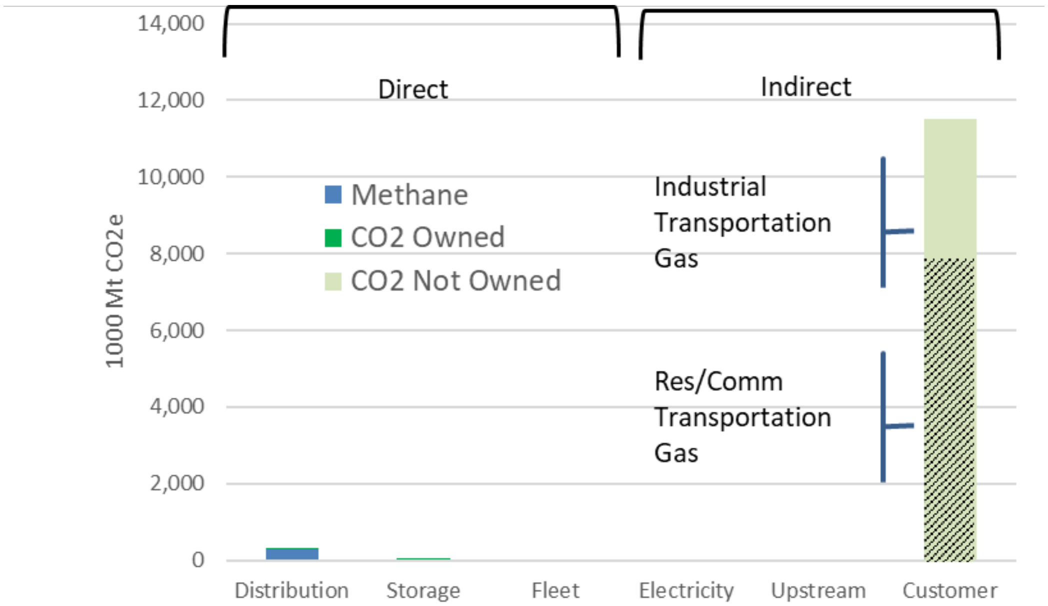
Figure 47 - Atlanta Gas Light Direct GHG Emissions - 2019 (1000 Mt CO2e)



Data Source: Atlanta Gas Light

Figure 48 and Table 37 show that indirect emissions related to customer gas use are much larger than any of the other sources, over 11 MMt CO_2e. All of the customer emissions are from gas purchased from Marketers or other third party suppliers. The upstream emissions from gas production, processing, and transportation are not included here because Atlanta Gas Light does not control and cannot track the emissions from gas provided by other entities.

Figure 48 - Atlanta Gas Light Direct and Indirect GHG Emissions - 2019 (1000 Mt CO2e)



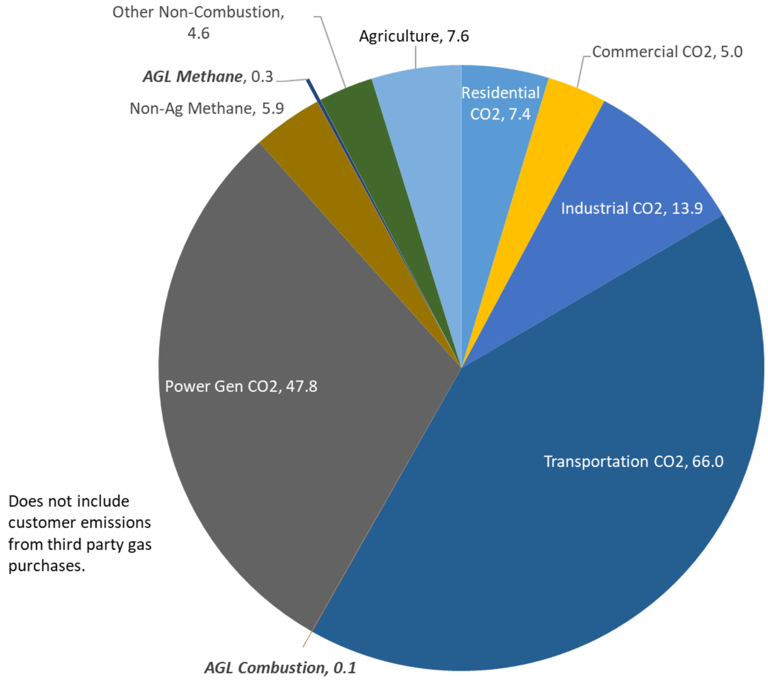
Data Source: Atlanta Gas Light

Table 37 - Atlanta Gas Light Direct and Indirect GHG Emissions - 2019 (1000 Mt CO_2e)

	Direct Emissions			Indirect Emissions			Total
	Distribution	Storage	Fleet	Electricity	Upstream	Customer	
Methane	275.9	0.1	0	0	0	0	**276.0**
Owned CO_2	1.2	35.8	13.0	4.2	0	0	**54.3**
Not Owned CO_2	0	0	0	0	0	11,520.5	**11,520.5**
Total	**277.1**	**35.9**	**13.0**	**4.2**	**0**	**11,520.5**	**11,850.8**

Figure 49 shows the Atlanta Gas Light emissions in the context of the estimated Georgia State GHG inventory.

Figure 49 - Estimated Georgia and Atlanta Gas Light GHG Emissions - 2019 (MMt CO_2e)



11.3 RNG for Atlanta Gas Light

The following tables summarize the maximum RNG potential for each biomass-based feedstock and production technology by geography of interest, reported in million cubic feet (MMcf). The RNG potential includes different variables for each feedstock, but ultimately reflects the most favorable options available, such as the highest biomass price and the utilization of all feedstocks at all facilities.

Table 38 –Technical Potential for Atlanta Gas Light RNG Production by Feedstock (MMcf/yr)

RNG Feedstock	Atlanta Gas Light	Rest of GA	Total
Animal Manure	30,994	26,831	57,825
Food Waste	2,437	496	2,932
Landfill Gas	28,194	4,636	32,830
Water Resource Recovery Facilities	1,552	352	1,904
Anaerobic Digestion Sub-Total	*63,177*	*32,315*	*95,492*
Agricultural Residue	13,071	46,955	60,026
Energy Crops	43,420	71,608	115,027
Forestry & Forest Product Residue	16,069	8,007	24,075
Municipal Solid Waste	21,474	4,387	25,861
Thermal Gasification Sub-Total	*94,033*	*130,957*	*224,990*
Total	157,209	163,272	320,482

ICF developed economic supply curves for three separate scenarios for each feedstock. The RNG potential included in the supply curves is based on an assessment of resource availability. In a competitive market, that resource availability is a function of multiple factors, including but not limited to demand, feedstock costs, technological development, accessibility to pipeline connections, and the policies in place that might support RNG project development. ICF assessed the RNG resource potential of the different feedstocks that could be realized, given the necessary market considerations (without explicitly defining what those are).

Table 39 - Projected Annual RNG Production in Atlanta Gas Light Service Territory by 2050 (MMcf/yr)

RNG Feedstock		Scenario		
		Limited Adoption	Moderate Deployment	High Utilization Deployment
Anaerobic Digestion	Animal Manure	3,854	7,768	11,735
	Food Waste	922	1,309	1,601
	LFG	5,972	10,771	15,496
	WRRFs	563	913	1,239
Thermal Gasification	Agricultural Residue	3,456	4,991	6,261
	Energy Crops	4,179	13,554	21,177
	Forestry and Forest Product Residue	4,821	8,034	11,248
	Municipal Solid Waste	4,737	8,242	10,737
Total		28,504	55,582	79,493

Figure 50 - Growth Scenarios for Annual RNG Production in Atlanta Gas Light Service Territory (MMcf/yr)

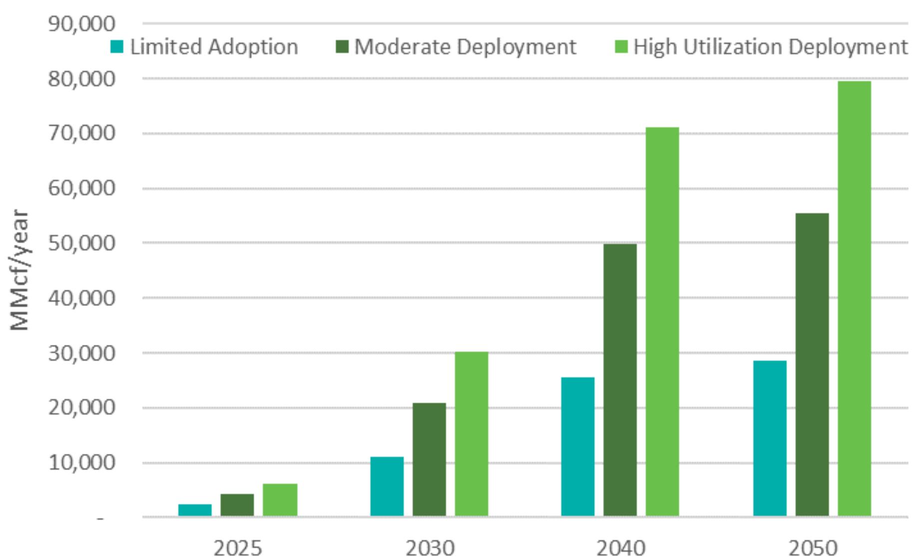


Figure 51 - P2G Production Scenarios for Atlanta Gas Light (MMcf/yr)

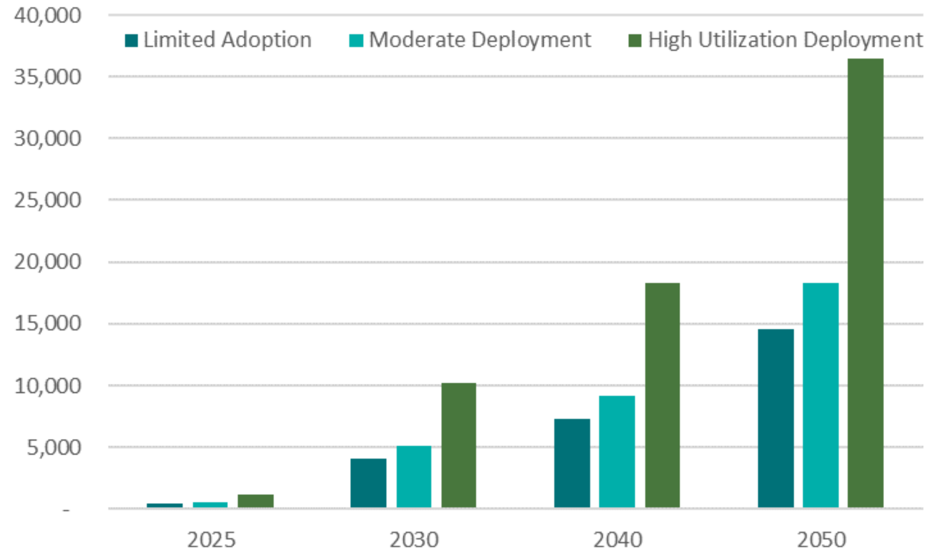


Figure 52 and Figure 53 present the RNG/P2G potential in the context of the Atlanta Gas Light deliveries. The left two bars show the gas deliveries in 2019 and potential deliveries in 2050 with the implementation of energy efficiency measures as in Scenario 2 discussed in Section 5.1.The three bars on the right side show the total amount of RNG/P2G and gas equivalent of offsets that are projected to be available in 2030, 2040, and 2050 in each of the three growth RNG scenarios. This does not include consumption of these resources for other uses than customer demand (i.e., offsetting direct emissions), which is addressed in the pathway analysis in Section 7.

Figure 52 – RNG Potential vs Atlanta Gas Light Gas Deliveries by Supply Case (MMcf/yr)

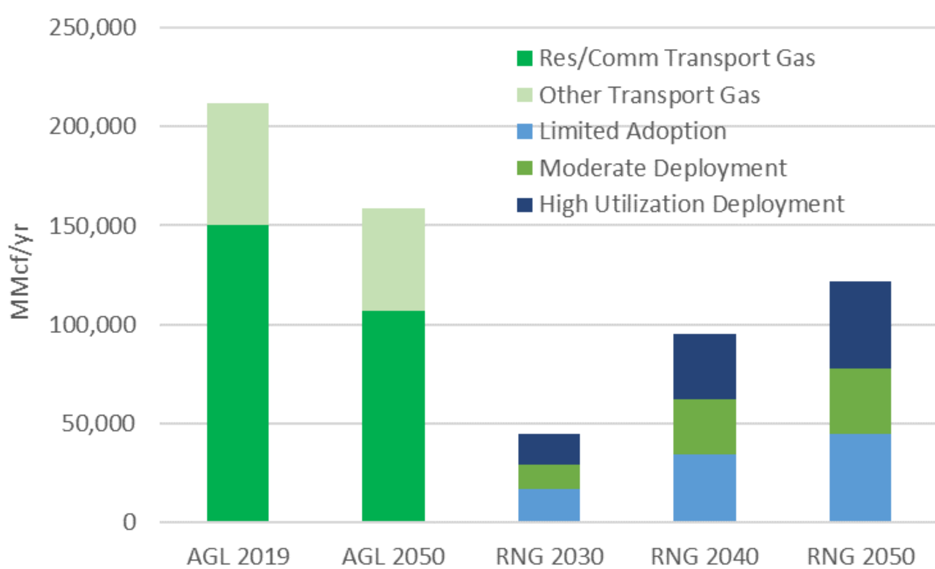


Figure 53 – RNG Potential vs Atlanta Gas Light Gas Deliveries by Supply Type (MMcf/yr)

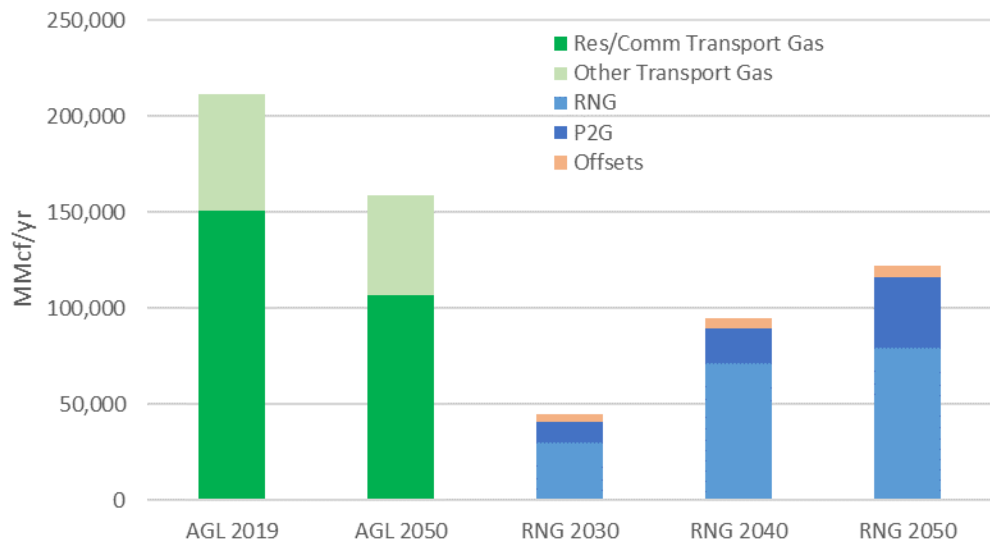
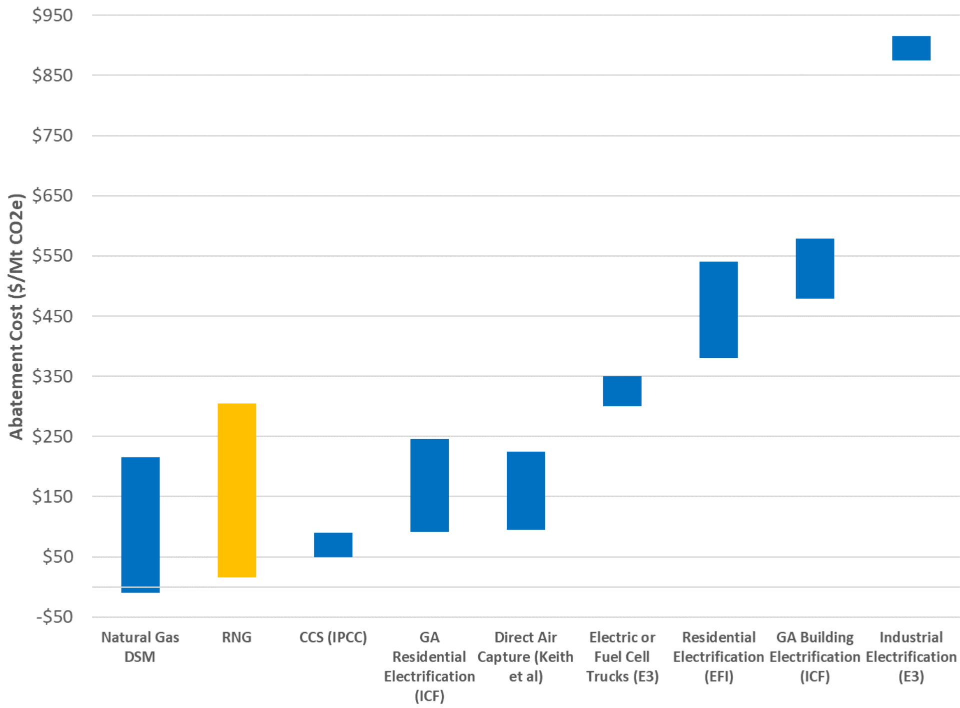


Figure 54 shows a comparison of selected measures across various key studies for specific abatement measures that are likely to be required for economy-wide decarbonization in the 2050 timeframe, including natural gas demand side management (DSM),[53] RNG (from this study), carbon capture and storage (CCS),[54] direct air capture (whereby CO_2 is captured directly from the air and a concentrated stream is sequestered or used for beneficial purposes),[55] battery electric trucks (including fuel cell drivetrains),[56] and policy-driven electrification of certain end uses (including buildings and in the industrial sectors).[57,58]

[53] See Con Edison's Smart Usage Rewards program (https://www.coned.com/en/save-money/rebates-incentives-tax-credits/smart-usage-rewards-for-reducing-gas-demand) and National Grid's Demand Response Pilot program (https://www.nationalgridus.com/GDR).
[54] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.).
[55] Keith, DW; Holmes, G; St Angelo D; Heidel, K; A Process for Capturing CO_2 from the Atmosphere, *Joule*, 2 (8), p1573-1594. https://doi.org/10.1016/j.joule.2018.05.006
[56] E3, 2018. Deep Decarbonization in a High Renewables Future, https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization
[57] Energy Futures Initiative (EFI), 2019. Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California, https://energyfuturesinitiative.org/efi-reports.
[58] ICF, 2018, Implications of Policy-Driven Residential Electrification, https://www.aga.org/globalassets/research--insights/reports/AGA_Study_On_Residential_Electrification.

Figure 54 - GHG Abatement Costs, Selected Measures ($/Mt CO_2e)



11.4 Direct Emission Reductions

Figure 55 shows the breakdown of the Atlanta Gas Light methane emissions, which totaled 11,041 Mt CH_4 in 2019 or 276 1000 Mt CO_2e weighted by the GWP. Three components accounted for 98% of the emissions. Customer meters comprised 25%, distribution mains and services comprised 55%, and dig-ins (damage to mains and services from construction) comprised 18%.

Figure 55 - Atlanta Gas Light Methane Emissions 2019 (Mt CH_4)

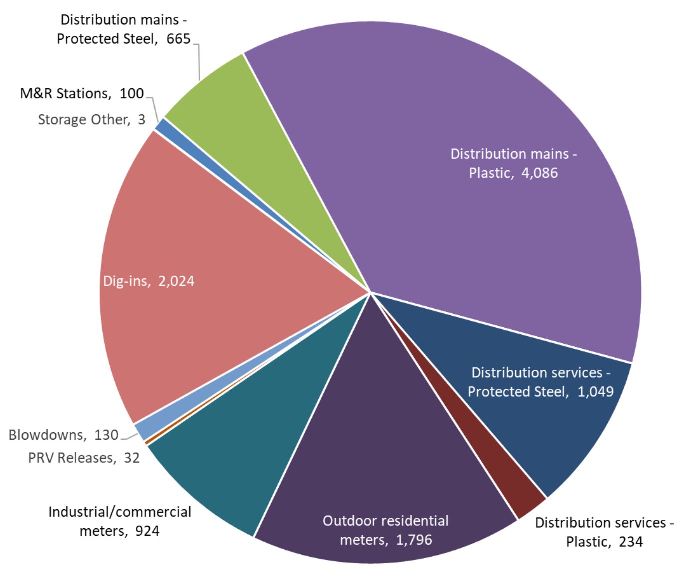


Table 40 summarizes the potential reduction in estimated methane emissions for the Atlanta Gas Light LDC and LNG storage facilities. The largest reductions are from enhanced LDAR and monitoring of meters. The total potential reduction is 21%.

Table 40 - Summary of Potential Atlanta Gas Light Methane Reductions (Mt CH_4)

	Pipes	Meters	Dig-Ins	Blowdowns	M&R Stations	LDC Total	LNG Storage	Grand Total
Baseline	6,034	2,719	2,024	1,30	131	11,038	3	11,041
Reductions	-	2,175	-	97	25	2,298	-	2,298
Remaining	6,034	544	2,024	33	106	8,740	3	8,743

11.5 Indirect Emission Reductions

This section provides details on the customer modeling for Atlanta Gas Light. The measures are installed gradually through requirements for new construction and stock turnover in existing buildings as shown in

Table 41. The implementation of gas heat pumps is more gradual due to the newness of the technology.

Table 41 - Technology Penetration in Gas Scenarios

Scenario 1 – Conventional Efficiency Options/RNG	Scenario 2 – High Efficiency Gas Technology/RNG
Implementation begins in 2025 Almost 80% of customers install high efficiency gas furnaces or boilers by 2050 35% of buildings get air sealing and add attic insulation by 2050	Implementation begins in 2025 Natural gas heat pumps start being adopted in 2025 and reach 54% of single family homes, 29% of multi-family, 40% of commercial buildings by 2050 29% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic insulation

Table 42 summarizes the results of the gas scenarios. The two scenarios are compared to a reference case in which gas demand continues to grow from current levels by about 19% through 2050 based on growth forecasts from the U.S. EIA Annual Energy Outlook.[59] The scenarios result in a 19% reduction in direct fuel use in 2050 for Scenario 1 and 33% in Scenario 2 compared to the reference case. In addition to the increased efficiency, the scenarios substitute RNG for conventional natural gas. In Scenario 1, efficiency plus RNG was able to reduce customer CO_2 emissions by 84% in 2050 relative to the reference case. In Scenario 2, efficiency plus RNG fully replaces conventional gas, resulting in a 98% reduction in CO_2 emissions from these customers. The table also shows the net present value cost of equipment installations through 2050 and incremental customer energy costs through 2080. (Energy costs through 2080 are included in order to include the operating costs of equipment

[59] https://www.eia.gov/outlooks/aeo/

installed in 2050 over a reasonable time period using that equipment.) The net present value of emission reductions through 2080 is then calculated in order to calculate an emission reduction cost in $/tonne CO_2 reduced. The emission reduction cost is $251/tonne CO_2 reduced for Scenario 1 and $262/tonne for Scenario 2 across all residential and commercial customers.

Table 42 - Summary of Atlanta Gas Light Gas Scenario Results

	2020 Base Year	Scenario 1 Conventional Efficiency Options/RNG	Scenario 2 High Efficiency Gas Technologies/ RNG
2050 Gas Consumption (Million MMBtu)	156	150	124
2050 Reduction in Gas Consumption vs. 2020 Base Year (%)		-4%	-20%
2050 Reduction in Gas Consumption vs. 2050 Reference Case (%)		-19%	-33%
2050 GHG Emissions (MMt CO_2 / year)	8	2	0.2
2050 Reduction in GHG Emissions vs. 2020 Base Year (%)		-81%	-97%
2050 Reduction in GHG Emissions vs. 2050 Reference Case (%)		-84%	-98%
Total Costs - NPV of Equipment and 2020-2080 Incremental Energy Costs ($2020 Millions)		29,702	36,058
NPV of GHG Emission Reductions (MMt CO_2)		119	138
Emission Reduction Costs ($/t$CO_2$)		$251	$262

The figures below provide additional context for the annual impacts for residential and commercial Atlanta Gas Light customers out to 2050, which drive the results presented in the Scenario Summary. Figure 56 shows the overall reduction in Atlanta Gas Light residential and commercial natural gas demand out to 2050.

Figure 56 – Atlanta Gas Light Annual Gas Demand Scenario 1 and 2 (Trillion Btu)

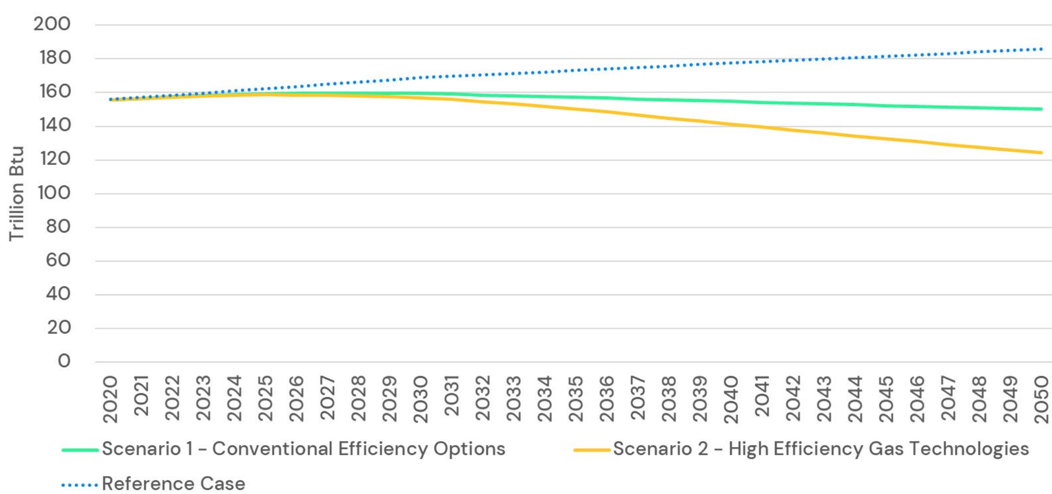


Figure 57 shows the total increase in energy costs from the gas scenarios, including the incremental upfront costs to install higher efficiency equipment and better insulate homes, changes in the energy costs to customers (based on reference case natural gas rates and the reduction in natural gas consumption), and incremental costs to purchase decarbonized gases (RNG and P2G). Figure 58 provides additional context on the make-up of those changes in customer energy costs.

Figure 57 – Atlanta Gas Light Total Annual Costs - Equipment Installations and Incremental Energy Costs) ($Millions)

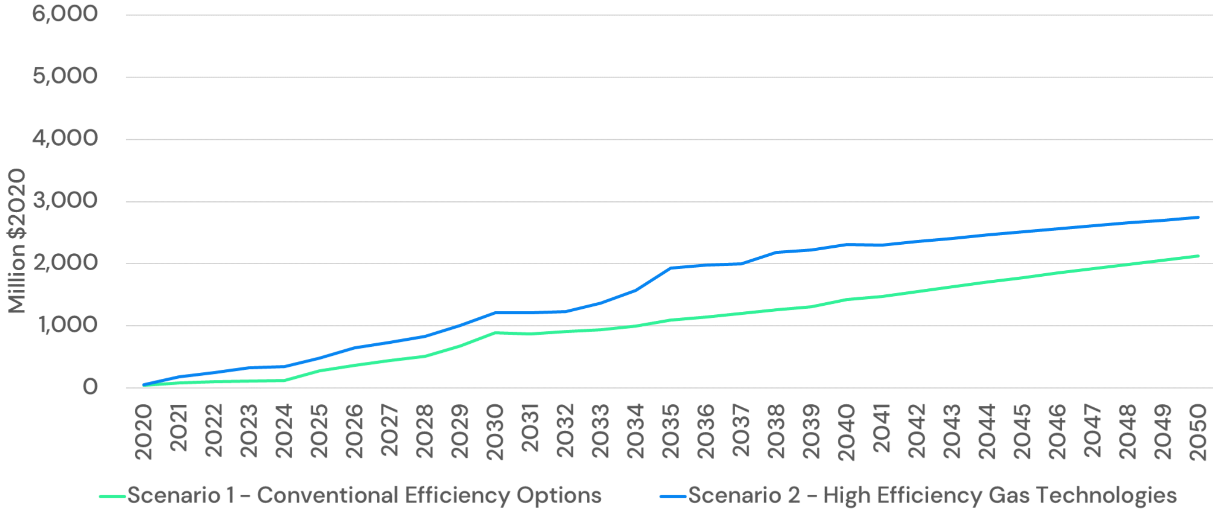


Figure 58 – Atlanta Gas Light Incremental Annual Energy Costs ($Millions)

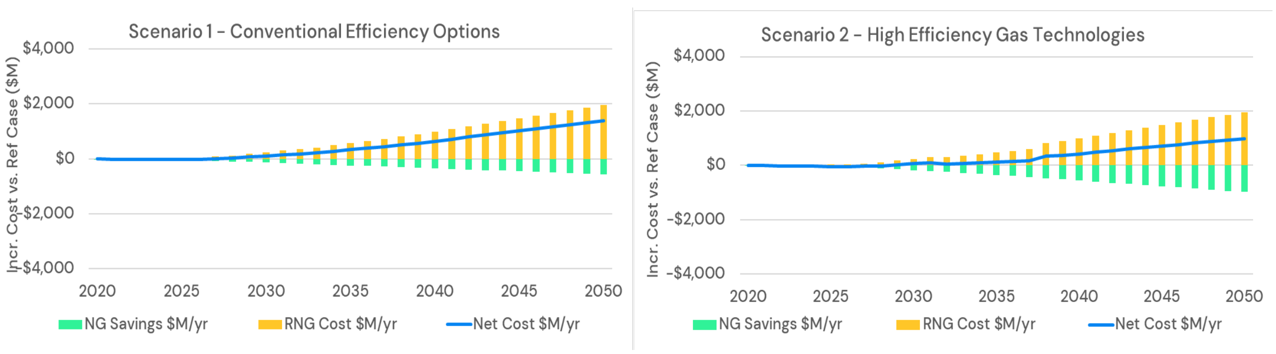


Figure 59 shows the emission reduction pathways for both of these scenarios. If RNG was not included in these scenarios, and no other changes were made, the GHG emission reductions would be reduced, matching gas demand reductions from Figure 1Figure 56, but the emission reductions costs ($/t$CO_2$) would also be lower.

Figure 59 – Atlanta Gas Light CO_2 Emissions from Natural Gas (Million tCO_2)

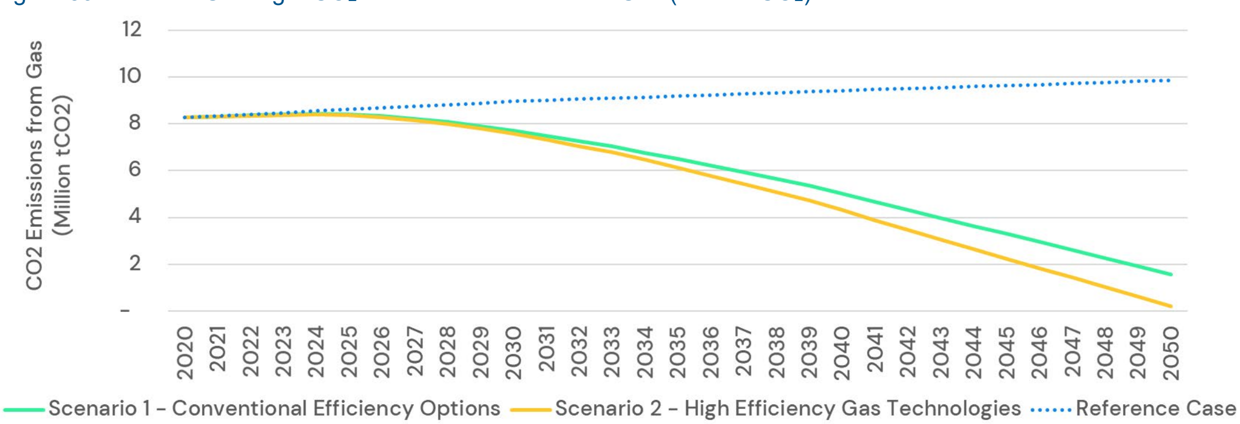


Table 43 summarizes the technology penetration assumptions for the electrification scenarios. Mandatory policies are assumed to require electrification for all new construction starting in

2025 and for all replacement/retrofits starting in 2030. The all-electric space heating share of single family homes reaches 90% of single family homes by 2050.

Table 43 - Technology Penetration in Atlanta Gas Light Electricity Scenarios

Scenario 3 – Policy-Driven Mandatory Electrification	Scenario 4 – Gas/Electric Hybrid Technology/RNG
Mandatory all-electric for new construction as of 2025. Mandatory conversion to electric space and water heating starting in 2030 when replacing equipment. All-electric space heating share reaches 90% in single family homes and 79% in commercial by 2050. Mix of ASHPs and electric resistance. 29% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic insulation	Starting in 2023 air-conditioning units get replaced with Air-Source Heat Pumps, forming hybrid-heating systems with the existing gas furnace. By 2050 hybrid heating reaches 76% of single family homes and 74% of commercial. 29% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic insulation

Table 44 summarizes the results of the electrification scenarios. The two scenarios are compared to a reference case in which gas demand continues to grow from current levels by about 19% through 2050 based on growth forecasts from Atlanta Gas Light and the U.S. EIA Annual Energy Outlook. The scenarios result in a reduction of direct fuel use by 74% for Scenario 3 and 49% in Scenario 4 in 2050, compared to the reference case. In addition to the electrification and efficiency improvements, Scenario 4 also meets the remaining gas demand with RNG (no RNG is used in Scenario 3). In Scenario 3, mandatory electrification and energy efficiency do not fully eliminate natural gas demand by 2050 because not all gas heating equipment is replaced and there are some non-heating/water heating gas applications that remain, resulting in an 74% reduction in natural gas CO_2 emissions from residential and commercial customers in 2050. In Scenario 4, targeted electrification, energy efficiency, plus RNG reduce customer CO_2 emissions by 100% in 2050. The table also shows the net present value of equipment installations through 2050 and incremental customer energy costs through 2080. (Energy costs through 2080 are included in order to include the operating costs of equipment installed in 2050 over a reasonable period of time using that equipment.)

Table 44 - Summary of Atlanta Gas Light Electric Scenario Results

	2020 Base Year	Scenario 3 Policy-Driven Mandatory Electrification	Scenario 4 Hybrid Gas/Electric Technologies
2050 Gas Consumption (Million MMBtu)	387	48	94
2050 Reduction in Gas Consumption vs. 2020 Base Year (%)	-	-69%	-39%
2050 Reduction in Gas Consumption vs. 2050 Reference Case (%)	-	-74%	-49%
2050 GHG Emissions (MMt CO_2 / year)	20.5	3	0
2050 Reduction in GHG Emissions vs. 2020 Base Year (%)	-	-69%	-100%

2050 Reduction in GHG Emissions vs. 2050 Reference Case (%)	-	-74%	-100%
Total Costs - NPV of Equipment and 2020-2080 Incremental Energy Costs ($2020 Millions)	-	52,353	44,411
NPV of GHG Emission Reductions (MMt CO_2)	-	99	140
Emission Reduction Costs ($/t$CO_2$)	-	$529	$317

Customer energy costs include changes in:

- Natural gas costs (based on reference case natural gas rates and the reduction in natural gas consumption),
- Costs for the additional electricity needed for electrified equipment (based on reference case electricity rates and the cost adders shown in Table 21,
- Cost increases on baseline electricity consumption (original customer electric load, less efficiency improvements, not including the newly electrified portion) for Atlanta Gas Light customers from the increase in electric rates assumed to be driven by the changes in these scenarios (based on the cost adders shown in Table 21, but showing just the cost increase incremental to changes that would occur for scenario 1 and 2 based on their respective adders; for example scenario 3 is based on impact for Atlanta Gas Light customers if electric rates went up 3.5 cents/kWh, while scenario 4 is based on a rate increase of 0.5 cents/kWh), and
- Incremental costs to purchase decarbonized gases (RNG and P2G for Scenario 4 only).

The net present value of emission reductions through 2080 is then calculated in order to calculate an emission reduction cost in $/tonne CO2 reduced. The emission reduction cost is $529/tonne CO_2 reduced for Scenario 3 and $317/tonne for Scenario 4, across all residential and commercial customers (there are differences in costs by customer types, with higher costs for commercial buildings). The targeted electrification with greater fuel flexibility assumed in Scenario 4 has a lower cost than the broader electrification requirement assumed in Scenario 3, as well as the value of continuing to leverage the gas distribution system to meet peak winter heating energy demand on the coldest days of the year. That said, it could have significant impacts on gas system operations and cost that are not included in this model, as discussed above.

The figures below provide additional context on the annual impacts for residential and commercial Atlanta Gas Light customers out to 2050, which drive the results summarized in the Scenario Summary. Figure 60 shows the overall reduction in Atlanta Gas Light residential and commercial natural gas demand out to 2050.

Figure 60 – Atlanta Gas Light Annual Gas Demand (Trillion Btu)

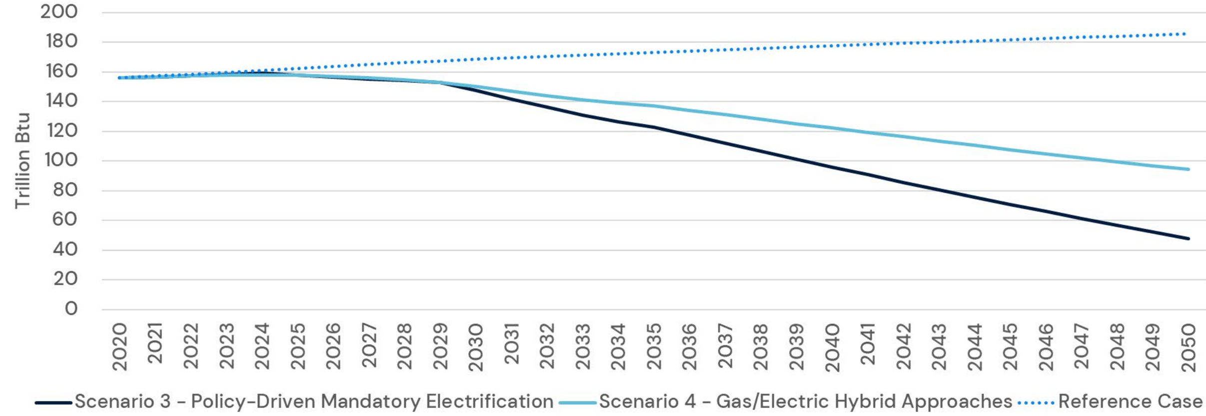


Figure 61 shows the total increase in energy costs from the electrification scenarios, including the incremental upfront costs to install higher efficiency equipment, electric equipment, or better insulate homes, and changes in the energy costs to customers.

Figure 61 – Atlanta Gas Light Total Annual Costs - Equipment Installations and Incremental Energy Costs ($Millions)

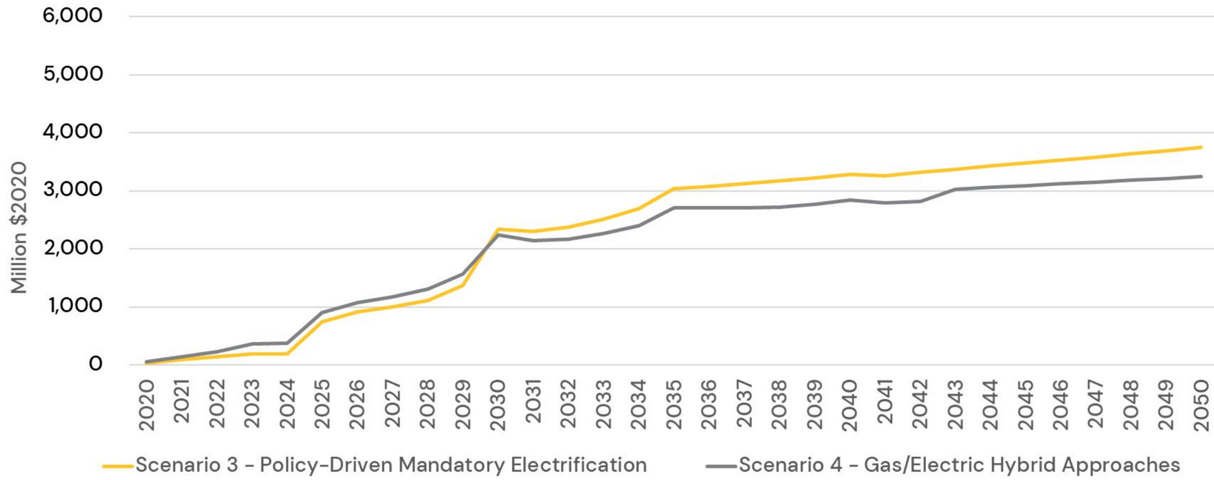


Figure 62 provides additional detail on the make-up of the changes in customer energy costs discussed above.

Figure 62 – Atlanta Gas Light Incremental Annual Energy Costs ($Millions)

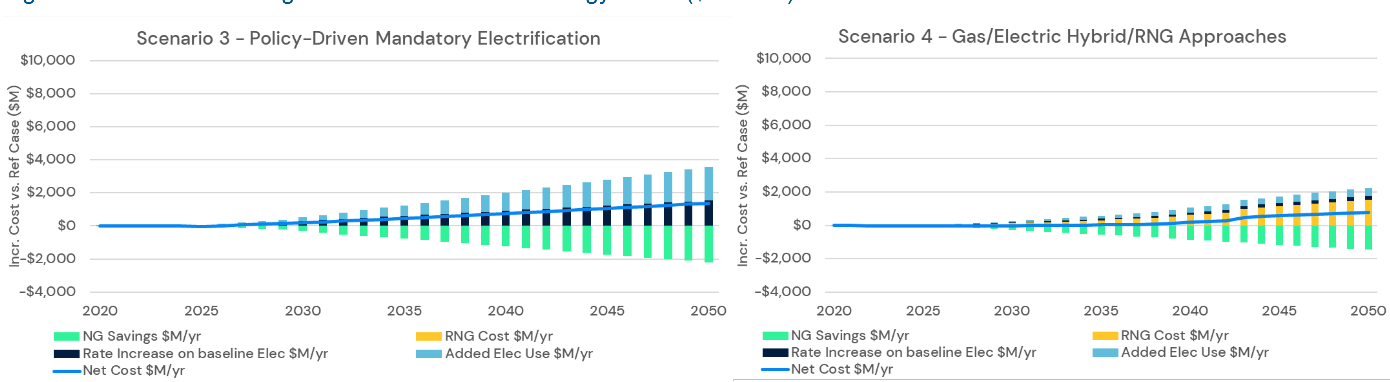


Figure 63 shows the emission reduction pathways for both of these scenarios. The use of RNG in the Gas/Electric Hybrid Scenario results in larger emission reductions by 2050 than the Policy-Driven Mandatory Electrification Scenario analyzed here.

Figure 63 – Atlanta Gas Light CO_2 Emissions from Natural Gas ($MMtCO_2$)

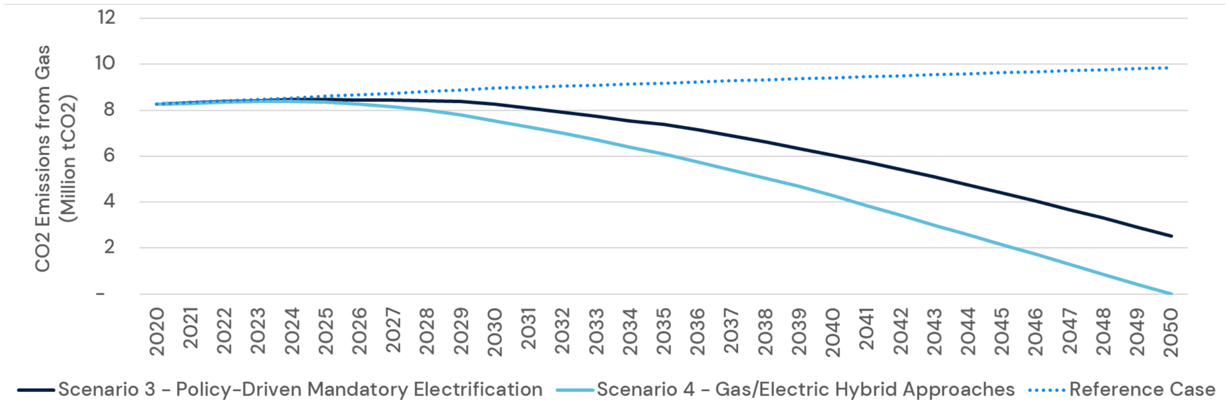


Table 45 summarizes the results of the residential and commercial customer scenario modeling. The natural gas decarbonization approaches (Scenarios 1 and 2) have the lowest consumer costs and the lowest emission reduction cost ($/tonne). The Hybrid Gas-Electric Technologies / RNG (Scenario 4) approach achieves the greatest GHG emission reduction, with the RNG available from sources considered here getting this scenario all the way to net-zero.

Table 45 – Atlanta Gas Light Summary of All Scenario Results

	2020	Scenario 1	Scenario 2	Scenario 3	Scenario 4
	Base Year	Conventional Efficiency Options/ RNG	High Efficiency Gas Technologies/ RNG	Policy-Driven Mandatory Electrification	Hybrid Gas/Electric Technologies/ RNG
2050 Gas Consumption (Million MMBtu)	156	150	124	48	94
2050 Reduction in Gas Consumption vs. 2020 Base Year (%)		-4%	-20%	-69%	-39%
2050 Reduction in Gas Consumption vs. 2050 Reference Case (%)		-19%	-33%	-74%	-49%
2050 GHG Emissions (MMt CO_2 / year)	8	2	0.2	3	0
2050 Reduction in GHG Emissions vs. 2020 Base Year (%)		-81%	-97%	-69%	-100%
2050 Reduction in GHG Emissions vs. 2050 Reference Case (%)		-84%	-98%	-74%	-100%

Total Costs - NPV of Equipment and 2020-2080 Incremental Energy Costs ($2020 Millions)		29,702	36,058	52,353	44,411
NPV of GHG Emission Reductions (MMt CO_2)		119	138	99	140
Emission Reduction Costs ($/t$CO_2$)		$ 251	$ 262	$ 529	$ 317

Figure 64 shows the key results graphically. The Policy-Driven Mandatory Electrification scenario has the highest cost to consumers but the lowest reduction in GHG emissions, resulting in a cost of reduction twice as high in $/tonne GHG reduced as the High Efficiency Gas scenario.

Figure 64 – Atlanta Gas Light Scenario Cost and Reduction Comparison

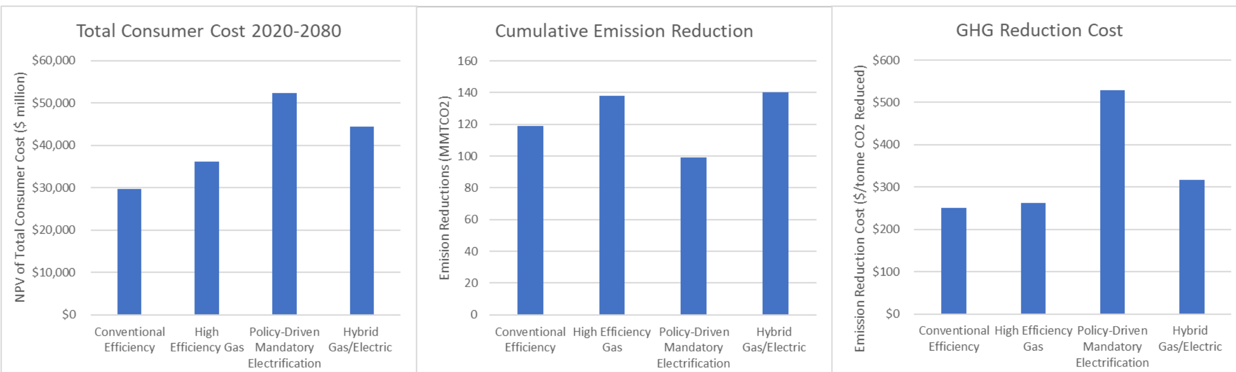


Table 46 shows the emission reduction cost by the various customer segments for new and existing building types. The gas technologies typically have the lowest cost due primarily to the deep reductions achieved through high efficiency and CO_2-neutral RNG. For scenarios 2, 3, and 4, higher emission reduction costs for new buildings (vs. existing buildings) reflect the cost increase to build 'net-zero ready' buildings with a lower thermal load, while the savings from such measures are only captured out to 2080 (and even then savings from the latter years are discounted by more years than the incremental home purchase cost). Scenario 1 includes more modest building shell improvements for new construction.

Table 46 – Atlanta Gas Light GHG Reduction Cost ($/tonne CO_2e)

Customer type	Vintage	$ Per Metric Ton of CO_2 2020-2080 (Discounted)			
		Scenario 1	Scenario 2	Scenario 3	Scenario 4
Single Family	**All vintages**	**$170**	**$160**	**$120**	**$101**
Single Family	New	$188	$247	$246	$217
Single Family	Existing	$165	$134	$91	$67
Multi-family	**All vintages**	**$206**	**$171**	**$227**	**$109**
Multi-family	New	$171	$153	$168	$119
Multi-family	Existing	$217	$176	$243	$105
Small Commercial	**All vintages**	**$462**	**$530**	**$2,107**	**$691**
Small Commercial	New	$624	$752	$2,144	$842
Small Commercial	Existing	$378	$415	$2,079	$613
Large Commercial	**All vintages**	**$603**	**$731**	**$4,335**	**$1,796**
Large Commercial	New	$845	$1,059	$5,456	$2,284

Large Commercial	Existing	$453	$525	$3,681	$1,489
Institutional	**All vintages**	**$329**	**$387**	**$1,633**	**$827**
Institutional	New	$389	$505	$1,971	$1,032
Institutional	Existing	$293	$314	$1,433	$699

11.6 Decarbonization Pathways for Atlanta Gas Light

Figure 65 illustrates a potential decarbonization pathway for the Atlanta Gas Light methane emissions. Baseline methane emissions can be expected to increase as Atlanta Gas Light adds new customers with meters, service lines, mains and with dig-ins, blowdowns, etc. The customer growth rate is as described for the customer emission modeling in Section 5.1, resulting in an emissions increase of 4% over 2019 in 2030 and 8% over 2019 in 2050. The largest reductions from the baseline emissions are expanded LDAR and improved quantification of methane emissions from meters. Despite the growth, the mitigation measures result in an estimated 19% reduction in methane emissions from 2019 by 2030 including estimates of system growth. The remaining methane emissions could be offset with methane capture offsets from RNG projects, resulting in net zero methane emissions in 2030 and continuing through 2050.

Figure 65 – Atlanta Gas Light Methane Emissions Reduction Pathway (1000 Mt CO_2e)

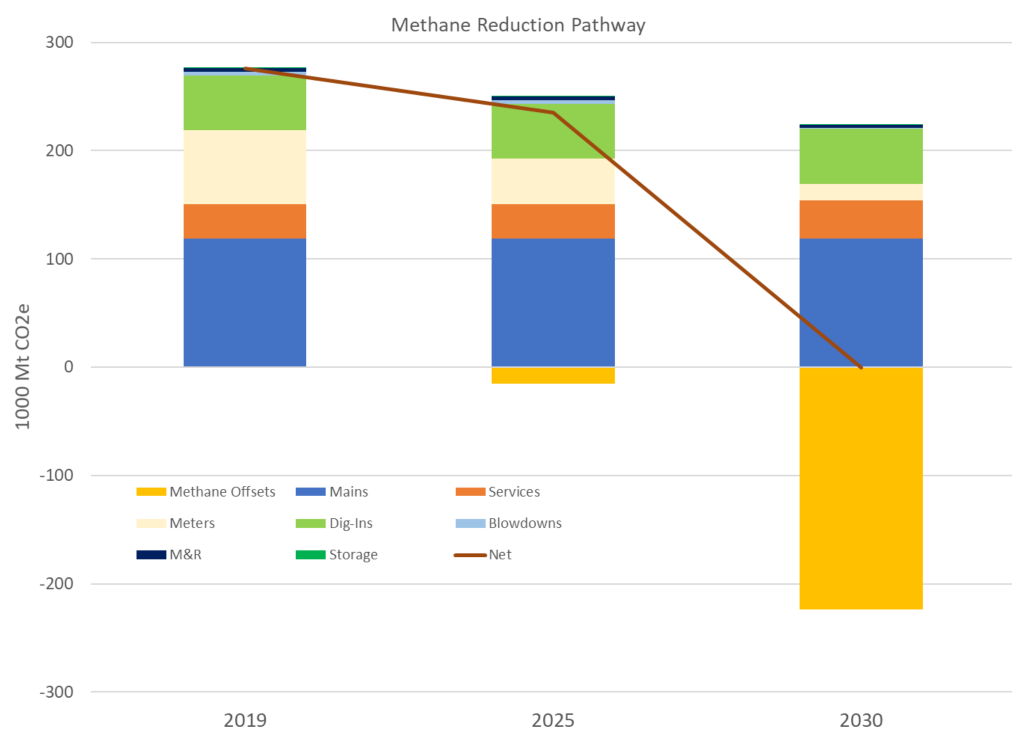
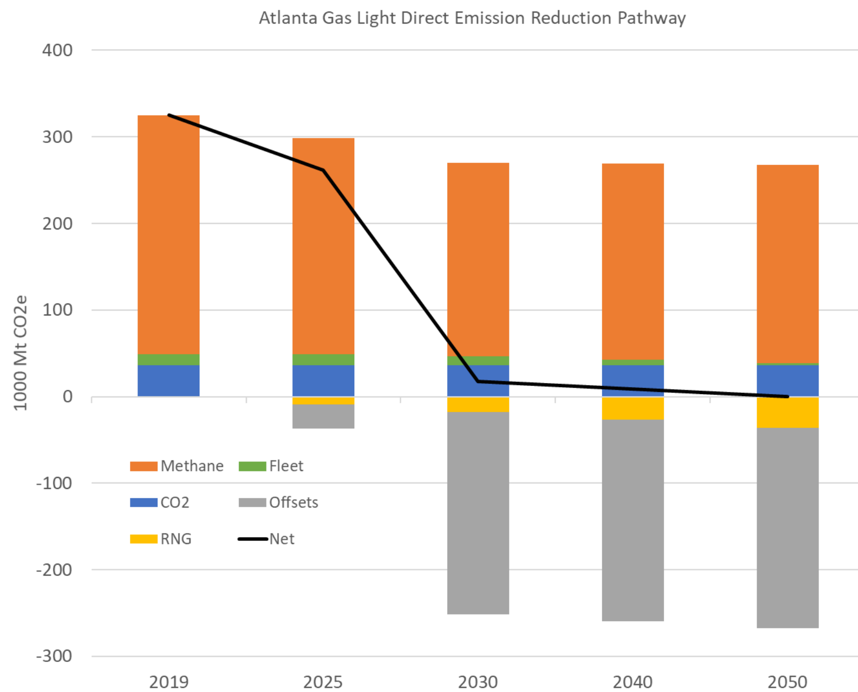


Figure 66 shows the reduction pathway for direct emissions including CO_2 from combustion at LNG storage facilities and fleet emissions. While there are several potential mitigation options for the LNG storage facilities, including electrification for compressors, this pathway assumes that the facilities are fueled with RNG to eliminate CO_2 emissions. That said, electrification for compressors could be considered as a future option depending on operational considerations for the LNG storage facility operation and decarbonization of the electric grid. Figure 66 shows that methane remains the largest component of direct emissions and methane capture offsets remain an important measure for achieving net zero emissions through 2050 with the addition of RNG to fuel the storage facilities.

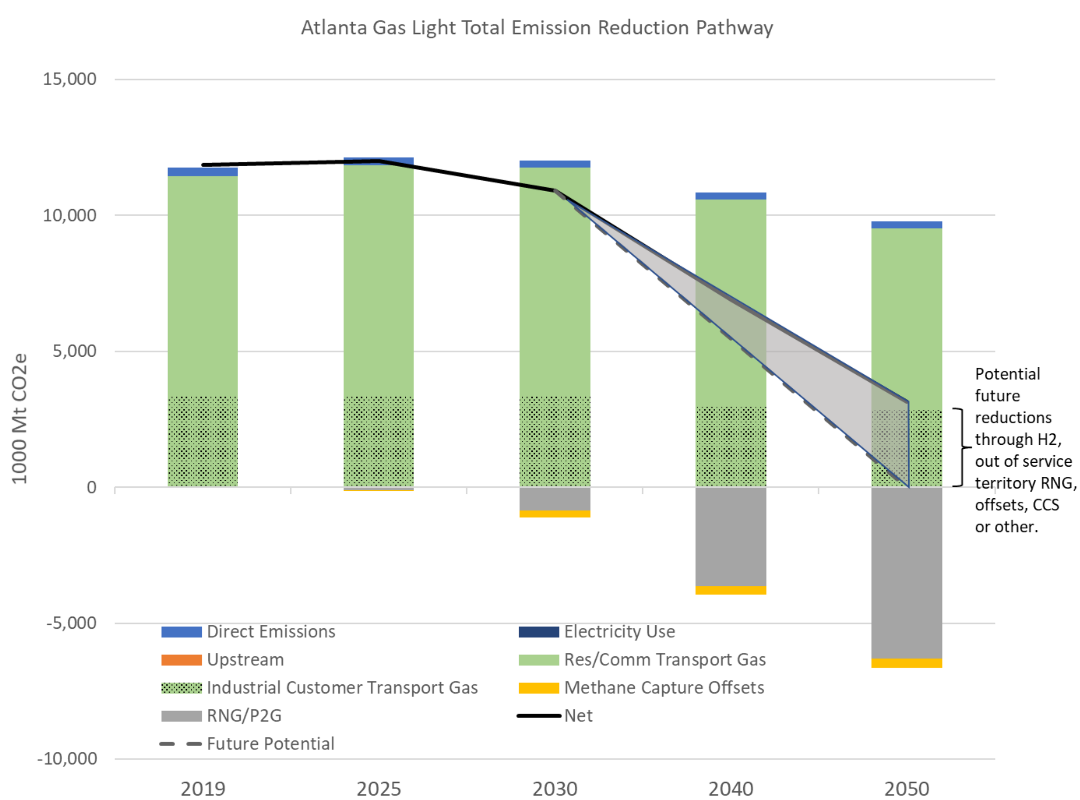
Figure 66 - Atlanta Gas Light Direct Emissions Reduction Pathway (1000 Mt CO_2e)



The Atlanta Gas Light indirect GHG emissions include only generation emissions for electricity that is used in-house by Atlanta Gas Light. As discussed earlier and shown in Figure 67, emissions from the customer use of gas are by far the largest source of direct or indirect emissions. As noted above, this pathway analysis includes emissions from all of Atlanta Gas Light's customers' use of gas, which is beyond Atlanta Gas Light's Scope 3 emissions under applicable GHG protocols, which would only include gas owned and sold by Atlanta Gas Light.

The direct and indirect emissions (including customer emissions) were projected to be reduced by 17% from 2019 to 2050. Using the High Utilization Deployment estimate of RNG, P2G, and offset availability, Atlanta Gas Light was projected to be net zero in 2050 for 96% of direct emissions and combustion emissions from transportation gas consumed by residential and commercial customers with resources inside the Atlanta Gas Light service territory. This results in a 73% estimated reduction in net emissions from 2019 to 2050. The remaining emissions from combustion of transportation gas delivered to Atlanta Gas Light industrial customers could potentially be reduced or offset through opportunities like hydrogen, RNG, combined heat and power, offsets from other sources, or use of carbon capture and sequestration.

Figure 67 - Atlanta Gas Light Total Emission Reduction Pathway (1000 Mt CO_2e)



12 Virginia Natural Gas (VNG)

12.1 Virginia Natural Gas Overview

Virginia Natural Gas (VNG) serves customers in the southeastern, Hampton Roads region of Virginia. VNG provides gas delivery service to over 300,000 customers. Residential customers made up 92% of the customers in 2019 and all of them purchased the gas commodity from VNG. Residential customers are smaller consumers on an Mcf/customer basis, accounting for only 14% of total deliveries. Most of the remaining customers were commercial sales customers. The remaining industrial sales customers and commercial, industrial, and electric generation customers made up less than 1% of the number of customers but the large majority of consumption. The 59 industrial transportation customers consumed nearly as much gas as the 276,000 residential customers. The industrial customers include 12 defense facilities that have critical national security missions and rely on gas for reliable energy service to complete those missions. Other large industrial customers include major food and agribusiness employers in the region.

There were only two listed electric generating customers, but they consumed 61% of the gas deliveries. One of the electric generating consumed almost 40% of total deliveries. The large commercial, industrial, and electric generating customers purchase gas directly from gas producers and marketers and consume 75% of total gas deliveries. This could be important if VNG offers alternative low GHG fuels, such as renewable natural gas (RNG) or hydrogen to its sales customers. Although VNG has a role to play in supporting the deployment of these alternative GHG fuels and promoting the development of RNG projects, these efforts will require their transportation customers. partnership among VNG, the suppliers, and their transportation customers. Transportation customers would have to look to their suppliers for these alternative fuels.

Table 47 - VNG Sales and Deliveries -2019

		Residential	Commercial	Industrial	Electric	Total
Sales	Customers	275,860	24,484	74	0	300,418
	Consumption (Mcf)	14,883,020	9,633,505	408,961	0	24,925,486
	Mcf/Customer	54	393	5,527	0	5,974
Transportation	Customers	0	144	59	2	205
	Consumption (Mcf)	0	4,913,836	12,513,381	67,265,920	84,693,137
	Mcf/Customer	0	34,124	212,091	33,632,960	33,879,175
Total	Customers	275,860	24,628	133	2	300,623
	Consumption (Mcf)	14,883,020	14,547,341	12,922,342	67,265,920	109,618,623

Figure 68 - VNG Customer Distribution – 2019 (1000)

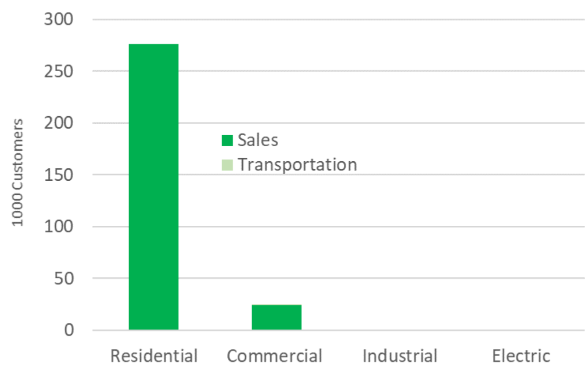
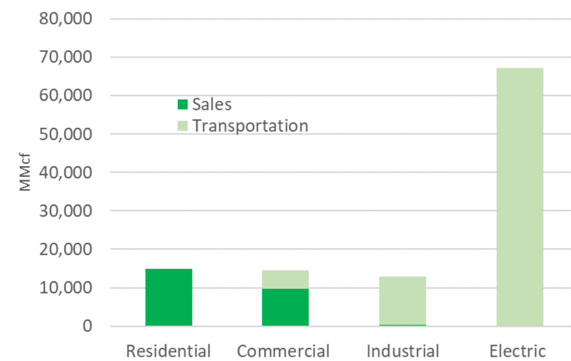


Figure 69 - VNG Delivery Distribution – 2019 (MMcf)



12.2 VNG Emissions

VNG's direct emissions totaled 74 thousand metric tonnes of CO_2 equivalent. The largest component was methane emissions from the distribution operations. CO_2 emissions from distribution system operations and fleet vehicles were much smaller.

Figure 70 - VNG Direct GHG Emissions - 2019 (1000 Mt CO2e)

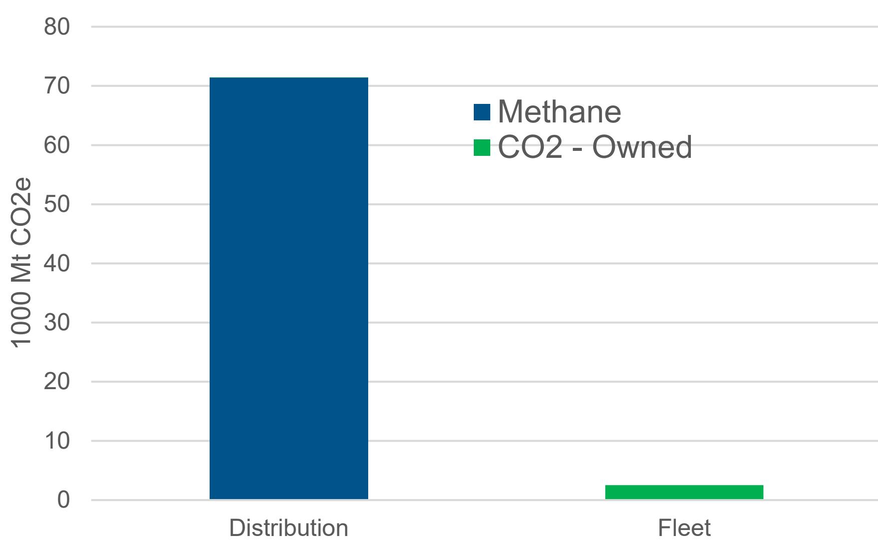


Figure 71 and

Table 48 show that VNG indirect emissions related to customer gas use were much larger than any of the other sources, totaling almost 6 million Mt CO_2e. Roughly 20% of the customer emissions were from gas owned and sold by VNG versus gas purchased from other sources by customers. The upstream emissions shown include only gas owned and sold by VNG because VNG does not control and cannot track the emissions from gas provided by other entities.

Table 48 - VNG Direct and Indirect GHG Emissions - 2019 (1000 Mt CO2e)

	Direct Emissions		Indirect Emissions			Total

	Distribution	Fleet	Electricity	Upstream	Customer	
Methane	71.4			127.1		**198.5**
Owned CO_2	<0.1	2.5	2.2	162.0	1,355.9	**1,522.7**
Not Owned CO_2					4,607.2	**4,607.2**
Total	**71.4**	**2.5**	**2.2**	**289.1**	**5,963.1**	**6,328.4**

Figure 71 - VNG Direct and Indirect Emissions - 2019 (1000 Mt CO2e)

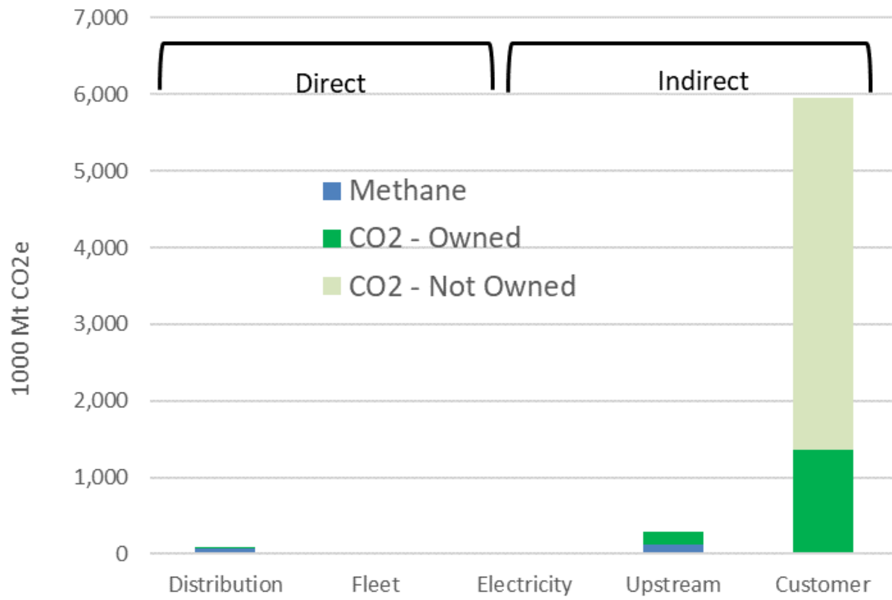
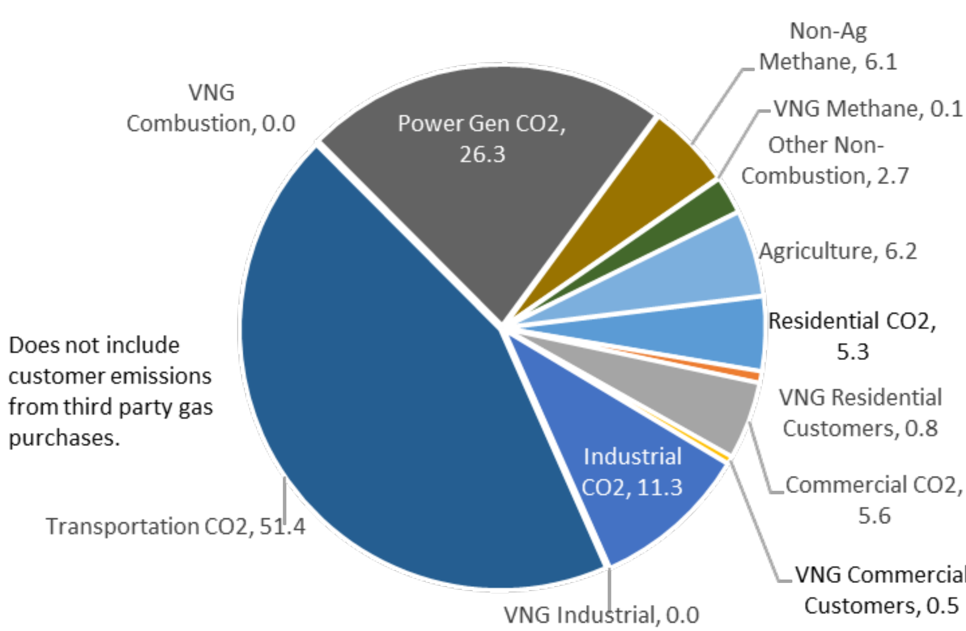


Figure 72 shows the VNG emissions compared to the estimated Virginia state GHG inventory.

Figure 72 - Estimated Virginia and VNG GHG Emissions - 2019 (MMt CO_2e)



12.3 RNG for VNG

The following table summarizes the maximum RNG potential for each biomass-based feedstock and production technology by geography of interest, reported in million cubic feet (MMcf). The RNG potential includes different variables for each feedstock, but ultimately reflects the most favorable options available, such as the highest biomass price and the utilization of all feedstocks at all facilities. The estimates included in this table is based on the maximum RNG production potential from all feedstocks, and does not apply any economic or technical constraints on feedstock availability.

Table 49 - Technical Potential for VNG RNG Production by Feedstock MMcf/yr)

RNG Feedstock	VNG	Rest of VA	Total
Animal Manure	673	38,900	39,573
Food Waste	436	2,030	2,466
Landfill Gas	8,433	23,992	32,425
Water Resource Recovery Facilities	428	1,407	1,835
Anaerobic Digestion Sub-Total	9,971	66,328	76,299
Agricultural Residue	1,905	7,175	9,080
Energy Crops	8,943	113,422	122,364
Forestry & Forest Product Residue	1,868	23,577	25,445
Municipal Solid Waste	3,843	17,902	21,745
Thermal Gasification Sub-Total	16,559	162,076	178,635
Total	26,530	228,404	254,933

ICF developed economic supply curves for three separate scenarios for each feedstock. The RNG potential included in the supply curves is based on an assessment of resource availability. In a competitive market, that resource availability is a function of multiple factors, including but not limited to demand, feedstock costs, technological development, accessibility to pipeline connections, and the policies in place that might support RNG project development. ICF assessed the RNG resource potential of the different feedstocks that could be realized, given the necessary market considerations (without explicitly defining what those are).

Table 50 - Projected Annual RNG Production in VNG Service Territory by 2050 (MMcf/yr)

RNG Feedstock		Scenario		
		Limited Adoption	Moderate Deployment	High Utilization Deployment
Anaerobic Digestion	Animal Manure	71	142	221
	Food Waste	144	201	257
	LFG	2,005	4,011	6,016
	WRRFs	195	309	405
Thermal Gasification	Agricultural Residue	392	781	938
	Energy Crops	1,611	2,662	3,735
	Forestry and Forest Product Residue	560	934	1,308
	Municipal Solid Waste	1,106	1,475	1,922
Total		6,085	10,514	14,802

Figure 73 - Growth Scenarios for Annual RNG Production in VNG Service Territory (MMcf/y)

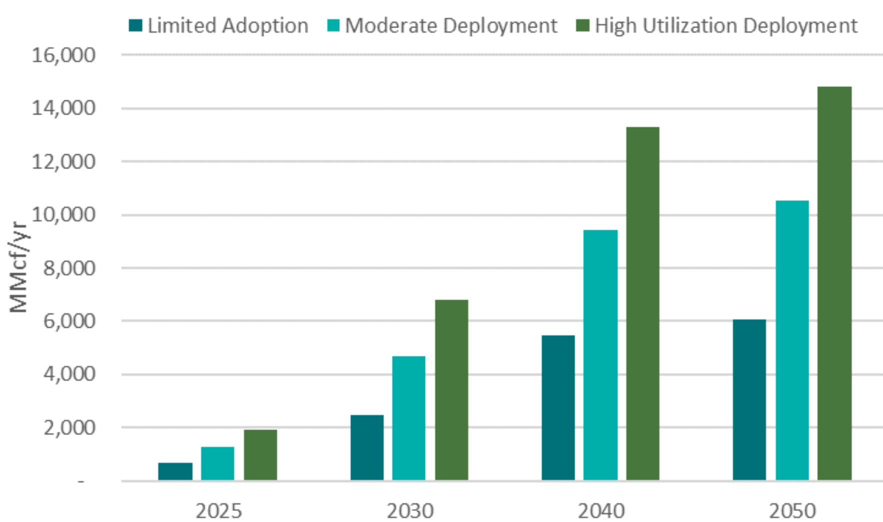


Figure 74 - P2G Production Scenarios for VNG (MMcf/y)

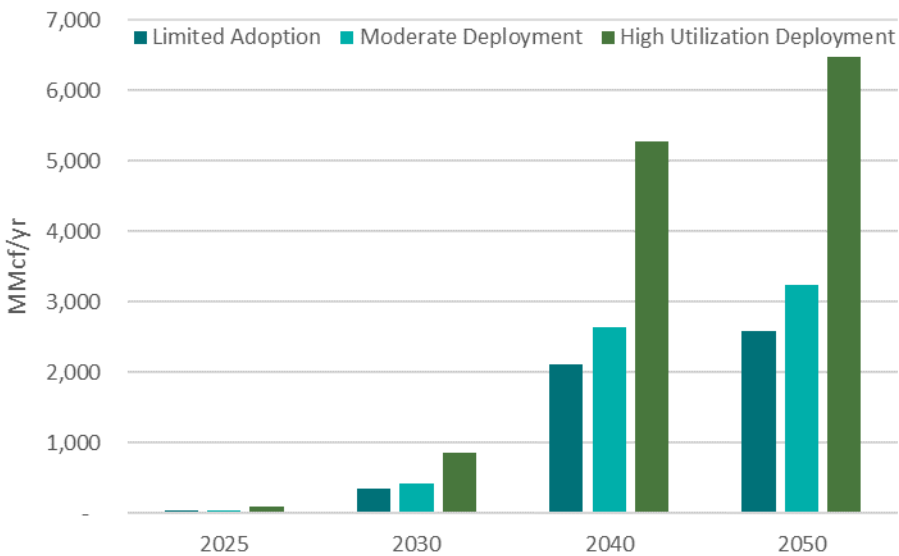


Figure 75 and Figure 76 present the RNG/P2G potential in the context of the VNG gas deliveries. The left two bars show the gas deliveries in 2019 and potential deliveries in 2050 with the implementation of energy efficiency measures as in Scenario 2 discussed in Section 5.1. The three bars on the right side show the total amount of RNG/P2G and gas equivalent of offsets that are projected to be available in 2030, 2040, and 2050 in each of the three growth RNG scenarios. This does not include consumption of these resources for other uses than customer demand (i.e., offsetting direct emissions), which is addressed in the pathway analysis in Section 7. Figure 76 shows the breakout of the RNG, P2G, and offset equivalent gas volume in the High Utilization Deployment case.

Figure 75 – RNG Potential vs VNG Gas Deliveries by Supply Case (MMcf/yr)

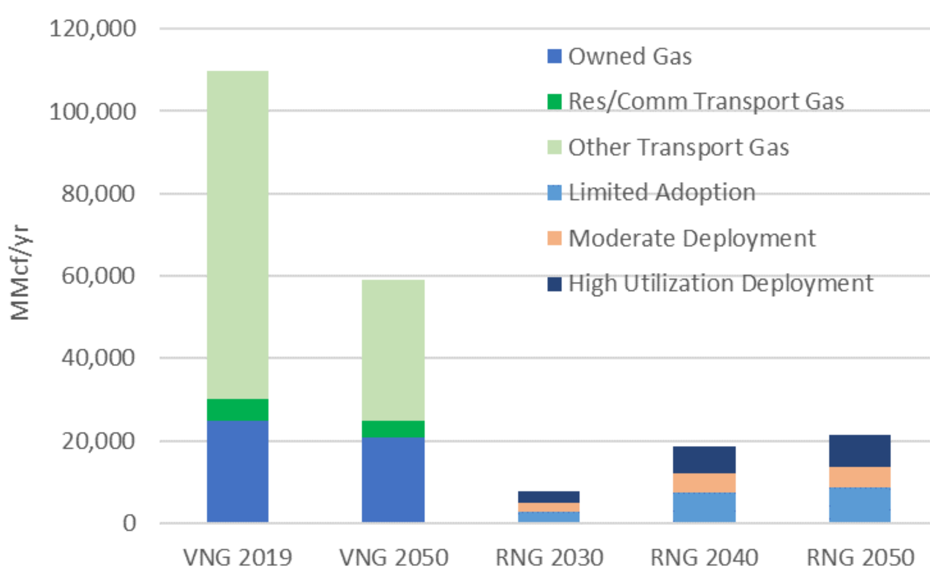


Figure 76 – RNG Potential vs VNG Gas Deliveries by Supply Type (MMcf/yr)

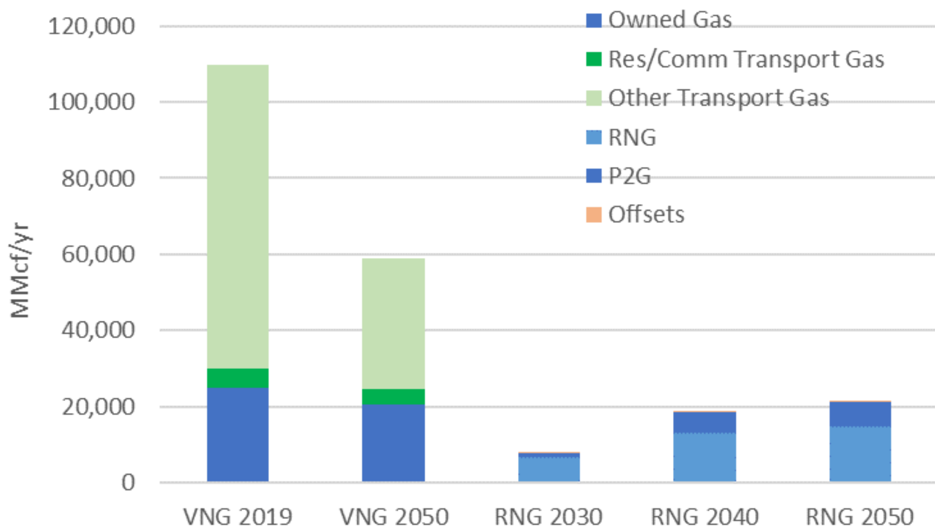
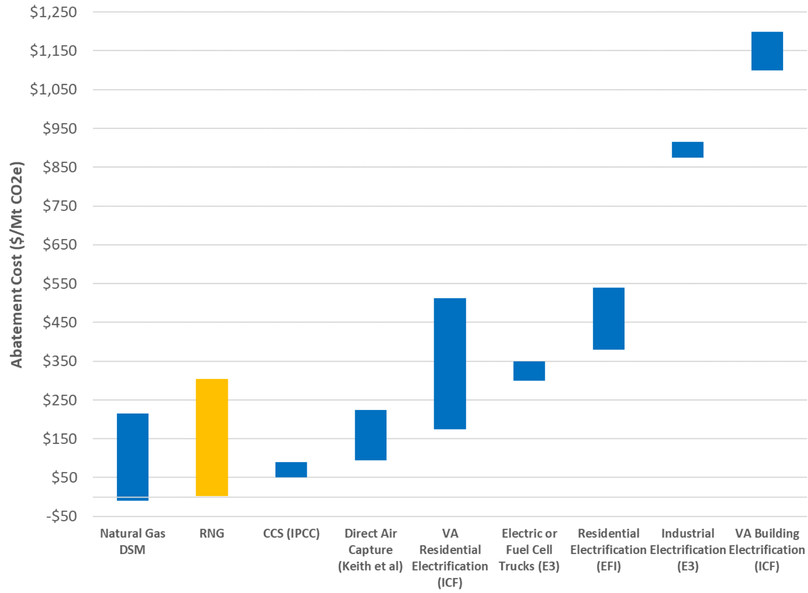


Figure 77 shows a comparison of selected decarbonization measures across various key studies for specific abatement measures that are likely to be required for economy-wide decarbonization in the 2050 timeframe, including natural gas demand side management (DSM),[60] RNG (from this study), carbon capture and storage (CCS),[61] direct air capture (whereby CO_2 is captured directly from the air and a concentrated stream is sequestered or used for beneficial purposes),[62] battery electric trucks (including fuel cell drivetrains),[63] and policy-driven electrification of certain end uses (including buildings and in the industrial sectors).[64,]

[60] See Con Edison's Smart Usage Rewards program (https://www.coned.com/en/save-money/rebates-incentives-tax-credits/smart-usage-rewards-for-reducing-gas-demand) and National Grid's Demand Response Pilot program (https://www.nationalgridus.com/GDR).
[61] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.).
[62] Keith, DW; Holmes, G; St Angelo D; Heidel, K; A Process for Capturing CO_2 from the Atmosphere, *Joule*, 2 (8), p1573-1594. https://doi.org/10.1016/j.joule.2018.05.006
[63] E3, 2018. Deep Decarbonization in a High Renewables Future, https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization
[64] Energy Futures Initiative (EFI), 2019. Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California, https://energyfuturesinitiative.org/efi-reports.

Figure 77 - GHG Abatement Costs, Selected Measures ($/Mt CO_2e)



12.4 Direct Emission Reductions

Figure 78 shows the breakdown of the methane emissions for VNG, which totaled 2,856 Mt CH_4 in 2019 or 71.4 1000 Mt CO_2e when weighted by the GWP. VNG estimates that it has reduced annual methane emissions from its distribution system from 1998 to 2018 by approximately 45% — even as the system grew by approximately 30%.

Figure 78 - VNG Methane Emissions 2019 (Mt CH_4)

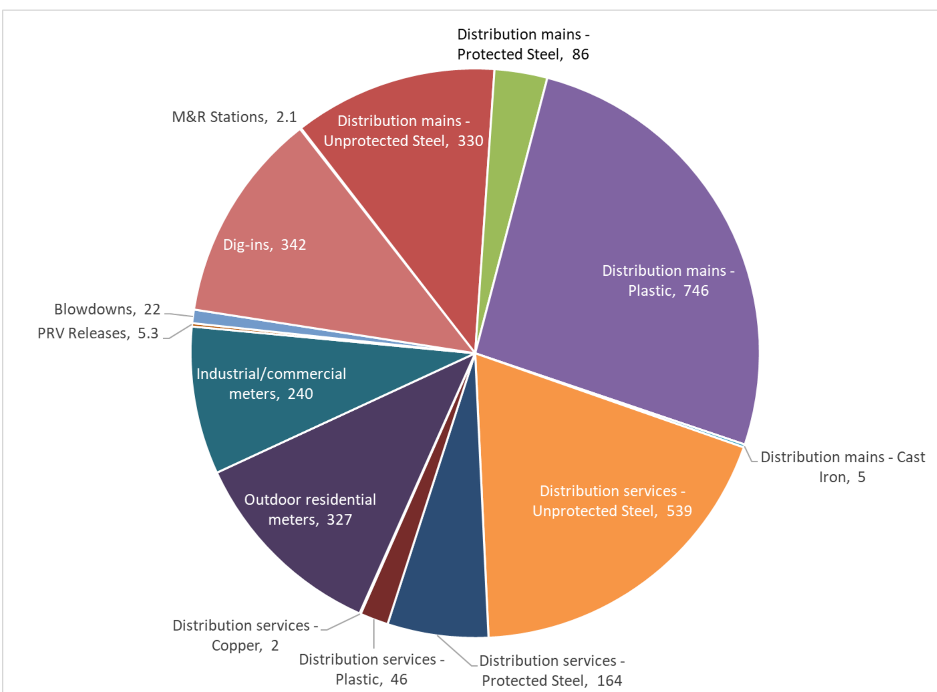


Table 51 summarizes the potential reduction in estimated methane emissions for the VNG LDC facilities. The largest reductions are from enhanced LDAR and monitoring of meters, followed by more accurate calculation of dig-in emissions. The total potential reduction is 53%.

Table 51 - Summary of Potential Methane Reductions (Mt CH_4)

	Pipes	Meters	Dig-Ins	Blowdowns	M&R Stations	LDC Total
Baseline	1,917	566	342	22	7.4	2,856
Reductions	842	453	196	16	0.5	1,509
Remaining	1,076	113	145	5	6.9	1,347

12.5 Indirect Emission Reductions

This section provides details on the customer modeling for VNG. The measures are installed gradually through requirements for new construction and stock turnover in existing buildings as shown in Table 52. The implementation of gas heat pumps is more gradual due to the newness of the technology.

Table 52 - Technology Penetration in Gas Scenarios

Scenario 1 – Conventional Efficiency Options/RNG	Scenario 2 – High Efficiency Gas Technology/RNG
Implementation begins in 2025 Almost 80% of customers install high efficiency gas furnaces or boilers by 2050 35% of buildings get air sealing and add attic insulation by 2050	Implementation begins in 2025 Natural gas heat pumps start being adopted in 2025 and reach 54% of single family homes, 29% of multi-family, 38% of commercial buildings by 2050 30% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic insulation

Table 53 summarizes the results of the gas scenarios for VNG. The two scenarios are compared to a reference case in which gas demand continues to grow from current levels by about 15% through 2050 based on growth forecasts from the U.S. EIA Annual Energy Outlook.[65] The scenarios result in a 19% reduction in direct fuel use in 2050 for Scenario 1 and 31% in Scenario 2 compared to the reference case. In addition to the increased efficiency, the scenarios substitute RNG for conventional natural gas. In Scenario 1, efficiency plus RNG was able to reduce customer CO_2 emissions by 79% in 2050. In Scenario 2, efficiency plus RNG fully replaces conventional gas, resulting in a 91% reduction in CO_2 emissions from these customers in 2050. The table also shows the net present value cost of equipment installations through 2050 and incremental customer energy costs through 2080. (Energy costs through 2080 are included in order to include the operating costs of equipment installed in 2050 over a reasonable time period using that equipment.) The net present value of emission reductions

[65] https://www.eia.gov/outlooks/aeo/

through 2080 is then calculated in order to calculate an emission reduction cost in \$/tonne CO_2 reduced. The emission reduction cost is \$325/tonne CO_2 reduced for Scenario 1 and \$374/tonne for Scenario 2 across all residential and commercial customers.

Table 53 - Summary of VNG Gas Scenario Results

	2020 Base Year	Scenario 1 Conventional Efficiency Options/RNG	Scenario 2 High Efficiency Gas Technologies/ RNG
2050 Gas Consumption (Million MMBtu)	31	30	25
2050 Reduction in Gas Consumption vs. 2020 Base Year (%)		-3%	-17%
2050 Reduction in Gas Consumption vs. 2050 Reference Case (%)		-19%	-31%
2050 GHG Emissions (MMt CO_2 / year)	1.62	0.40	0.17
2050 Reduction in GHG Emissions vs. 2020 Base Year (%)		-75%	-90%
2050 Reduction in GHG Emissions vs. 2050 Reference Case (%)		-79%	-91%
Total Costs - NPV of Equipment and 2020-2080 Incremental Energy Costs (\$2020 Millions)		7,125	9,408
NPV of GHG Emission Reductions (MMt CO_2)		22	25
Emission Reduction Costs (\$/tCO_2)		\$ 325	\$ 374

The figures below provide additional context for the annual impacts for residential and commercial VNG customers out to 2050, which drive the results showcased in the above Scenario Summary. Figure 79 shows the overall reduction in VNG residential and commercial natural gas demand out to 2050.

Figure 79 – VNG Annual Gas Demand (Trillion Btu)

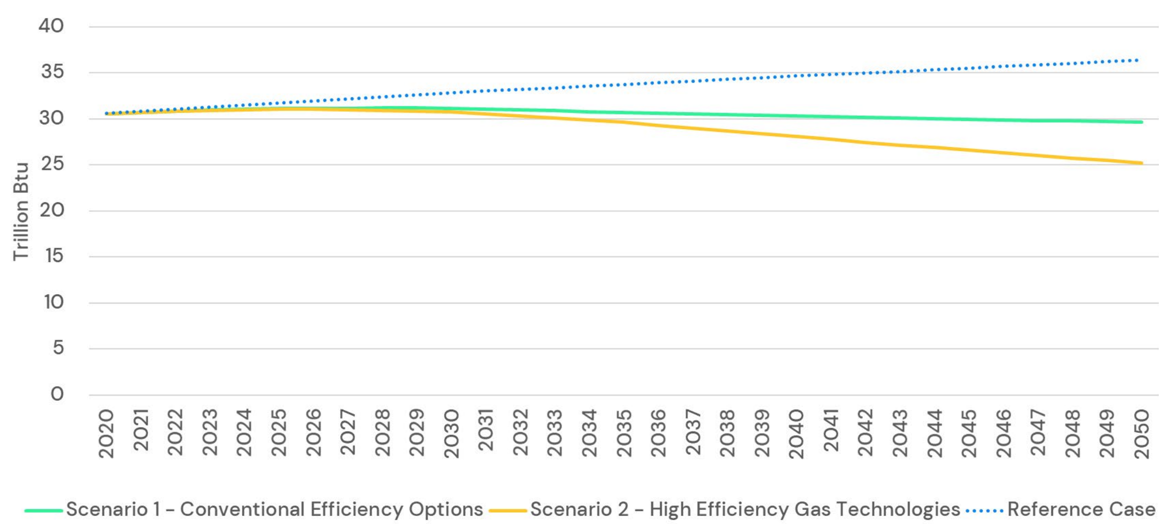


Figure 80 shows the total increase in energy costs from the gas scenarios, including the incremental upfront costs to install higher efficiency equipment and better insulate homes, changes in the energy costs to customers (based on reference case natural gas rates and the reduction in natural gas consumption), and incremental costs to purchase decarbonized gases

(RNG and P2G). Figure 81 provides additional context on the make-up of those changes in customer energy costs.

Figure 80 – VNG Total Annual Costs - Equipment Installations and Incremental Energy Costs) ($Millions)

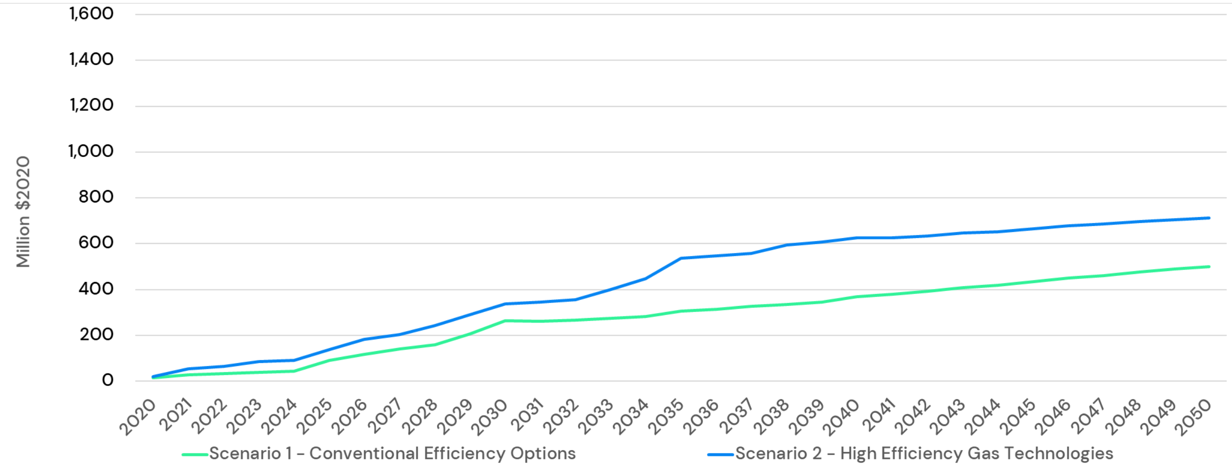


Figure 81 – VNG Incremental Annual Energy Costs ($Millions)

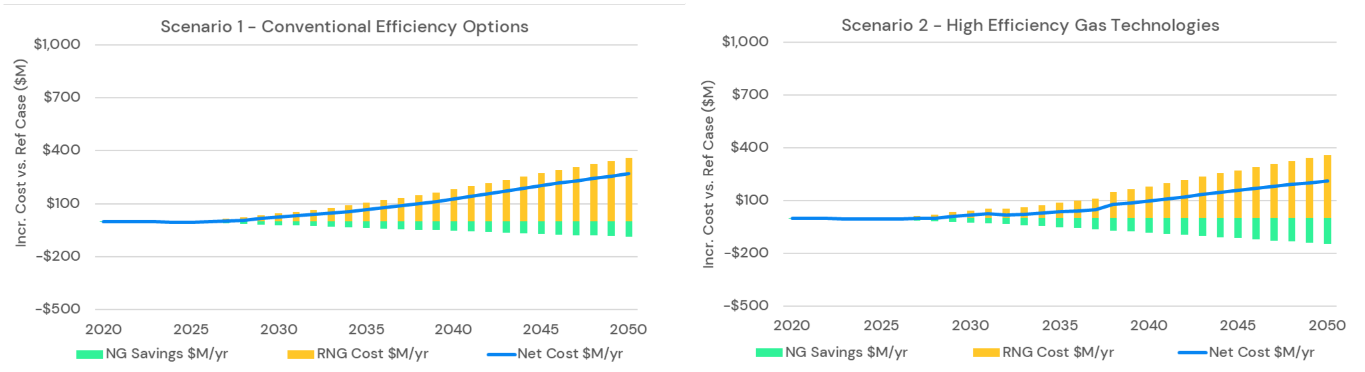


Figure 82 shows the emission reduction pathways for both of these scenarios. If RNG was not included in these scenarios, and no other changes were made, the GHG emission reductions would be reduced, matching gas demand reductions from Figure 79, but the emission reductions costs ($/tCO$_2$) would also be lower.

Figure 82 – VNG CO_2 Emissions from Natural Gas (Million tCO_2)

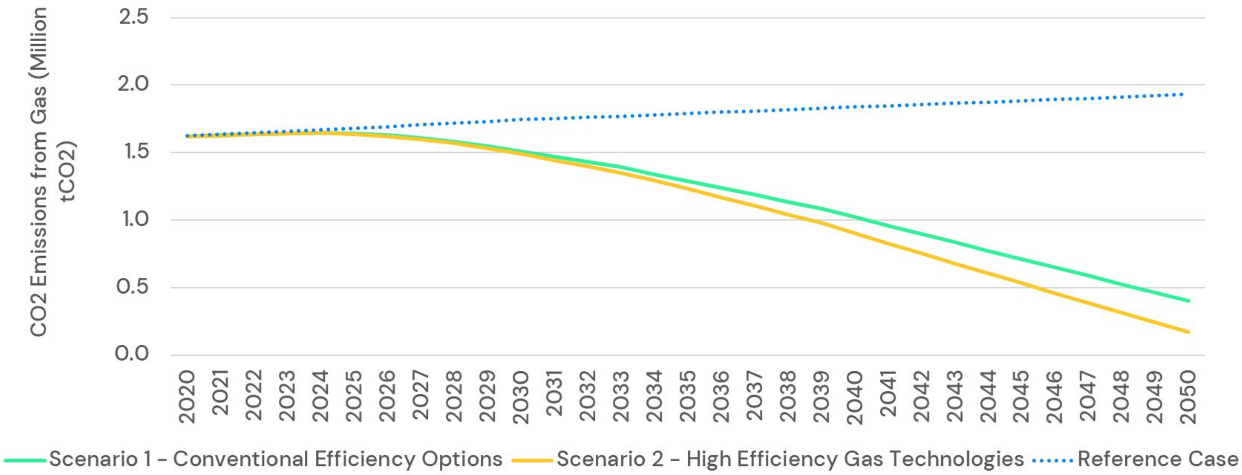


Table 54 summarizes the technology penetration assumptions for the electrification scenarios. Mandatory policies are assumed to require electrification for all new construction starting in 2025 and for all replacement/retrofits starting in 2030. The all-electric space heating share of single family homes reaches 93% of single family homes by 2050.

Table 54 - Technology Penetration in Electricity Scenarios

Scenario 3 – Policy-Driven Mandatory Electrification	Scenario 4 – Gas/Electric Hybrid Technology/RNG
Mandatory all-electric for new construction as of 2025. Mandatory conversion to electric space and water heating starting in 2030 when replacing equipment. All-electric space heating share reaches 93% in single family homes and 87% in commercial by 2050. Mix of ASHPs and electric resistance. 30% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic insulation	Starting in 2023 air-conditioning units get replaced with Air-Source Heat Pumps, forming hybrid-heating systems with the existing gas furnace. By 2050 hybrid heating reaches 75% of all buildings. 30% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic insulation

Table 55 summarizes the results of the VNG electrification scenarios. The two scenarios are compared to a reference case in which gas demand continues to grow from current levels by about 19% through 2050 based on growth forecasts from the U.S. EIA Annual Energy Outlook. The scenarios result in a reduction of direct fuel use in 2050 by 71% for Scenario 3 and 45% in Scenario 4, compared to the reference case in 2050. In addition to the electrification and efficiency improvements, Scenario 4 also meets the remaining gas demand with RNG (no RNG is used in Scenario 3). In Scenario 3, mandatory electrification and energy efficiency do not fully eliminate natural gas demand by 2050 because not all gas heating equipment is replaced and there are some non-heating/water heating gas applications that remain, resulting in a 71% reduction in natural gas CO_2 emissions from residential and commercial customers. In Scenario 4, targeted electrification, energy efficiency, plus RNG reduce customer CO_2 emissions by 100%. The table also shows the net present value of equipment installations through 2050 and incremental customer energy costs through 2080. (Energy costs through 2080 are included in order to include the operating costs of equipment installed in 2050 over a reasonable period of time using that equipment.)

Table 55 - Summary of Electric Scenario Results

	2020 Base Year	Scenario 3 Policy-Driven Mandatory Electrification	Scenario 4 Hybrid Gas/Electric Technologies
2050 Gas Consumption (Million MMBtu)	31	10	20
2050 Reduction in Gas Consumption vs. 2020 Base Year (%)		-66%	-35%
2050 Reduction in Gas Consumption vs. 2050 Reference Case (%)		-71%	-45%
2050 GHG Emissions (MMt CO_2 / year)	1.62	0.55	0.00
2050 Reduction in GHG Emissions vs. 2020 Base Year (%)		-66%	-100%
2050 Reduction in GHG Emissions vs. 2050 Reference Case (%)		-71%	-100%
Total Costs - NPV of Equipment and 2020-2080 Incremental Energy Costs ($2020 Millions)		21,570	17,409
NPV of GHG Emission Reductions (MMt CO_2)		19	28
Emission Reduction Costs ($/t$CO_2$)		$ 1,149	$ 633

Customer energy costs include changes in:

- Natural gas costs (based on reference case natural gas rates and the reduction in natural gas consumption),
- Costs for the additional electricity needed for electrified equipment (based on reference case electricity rates and the cost adders shown in Table 21),
- Cost increases on baseline electricity consumption (original customer electric load, less efficiency improvements, not including the newly electrified portion) for VNG customers from the increase in electric rates assumed to be driven by the changes in these scenarios (based on the cost adders shown in Table 21, but showing just the cost increase incremental to changes that would occur for scenario 1 and 2 based on their respective adders; for example scenario 3 is based on impact for VNG customers if electric rates went up 3.5 cents/kWh, while scenario 4 is based on a rate increase of 0.5 cents/kWh), and
- Incremental costs to purchase decarbonized gases (RNG and P2G for Scenario 4 only).

The net present value of emission reductions through 2080 is then calculated in order to calculate an emission reduction cost in $/tonne CO_2 reduced. The emission reduction cost is $1,149/tonne CO_2 reduced for Scenario 3 and $633/tonne for Scenario 4, across all residential and commercial customers (there are differences in costs by customer types, with higher costs for commercial buildings). The targeted electrification with greater fuel flexibility assumed in Scenario 4 has a lower cost than the broader electrification requirement assumed in Scenario 3, as well as the value of continuing to leverage the gas distribution system to meet peak winter heating energy demand on the coldest days of the year. That said, it could have significant impacts on gas system operations and cost that are not included in this model, as discussed above.

The figures below provide additional context on the annual impacts for residential and commercial VNG customers out to 2050, which drive the results summarized in the Scenario Summary. Figure 83 shows the overall reduction in VNG residential and commercial natural gas demand out to 2050.

Figure 83 – VNG Annual Gas Demand (Trillion Btu)

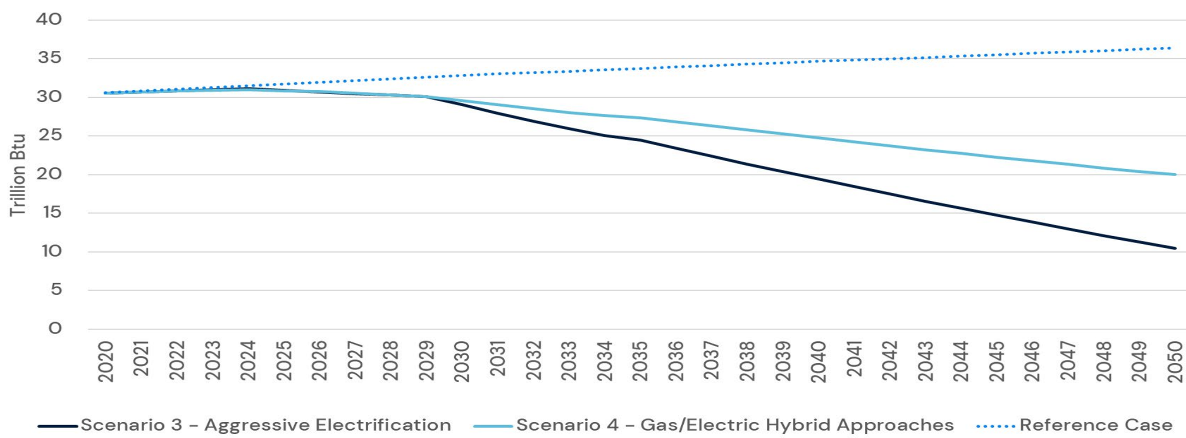


Figure 84 shows the total increase in energy costs from the electrification scenarios, including the incremental upfront costs to install higher efficiency equipment, electric equipment, or better insulate homes, and changes in the energy costs to customers.

Figure 84 – VNG Total Annual Costs - Equipment Installations and Incremental Energy Costs ($Millions)

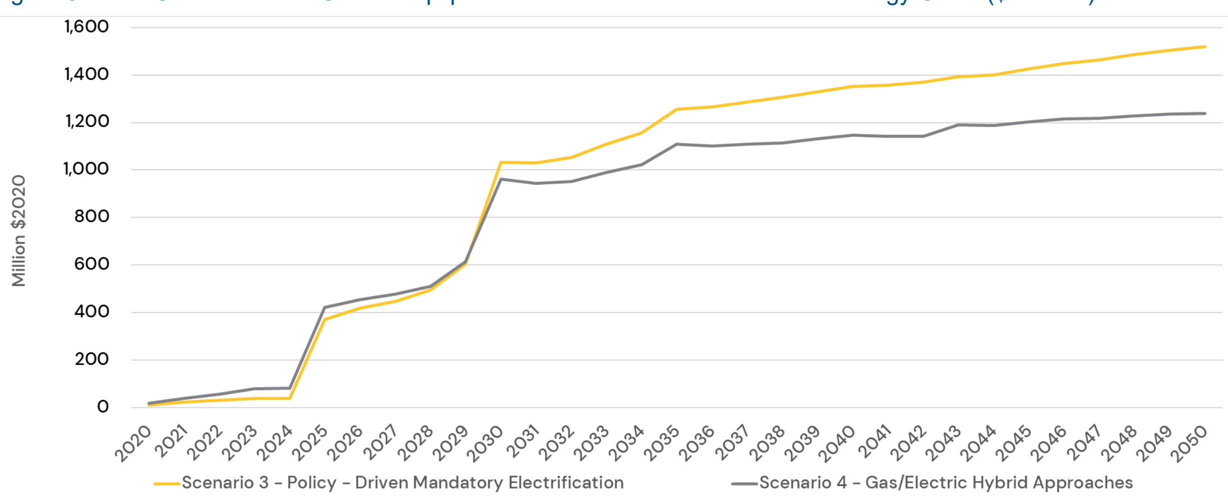


Figure 85 provides additional detail on the make-up of the changes in customer energy costs discussed above.

Figure 85 – VNG Incremental Annual Energy Costs ($Millions)

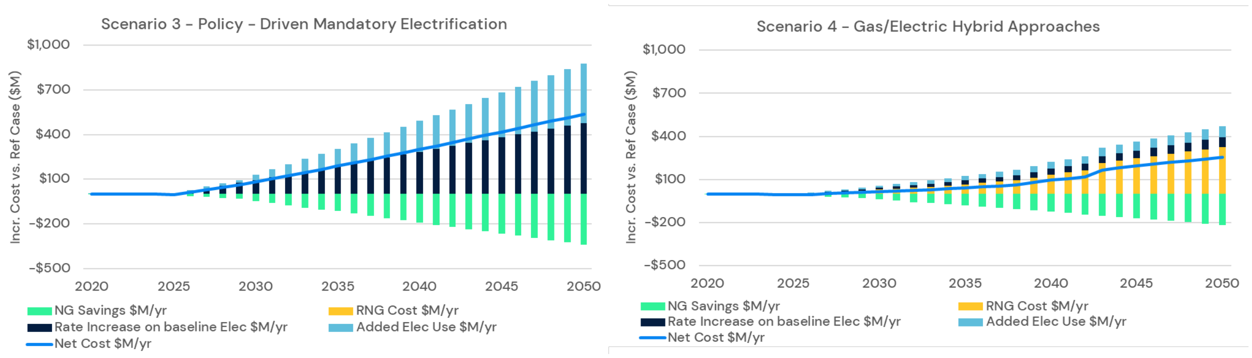


Figure 86 shows the emission reduction pathways for both of these scenarios. The use of RNG in the Gas/Electric Hybrid Scenario results in larger emission reductions by 2050 than the Policy-Driven Mandatory Electrification Scenario analyzed here.

Figure 86 – CO_2 Emissions from Natural Gas ($MMtCO_2$)

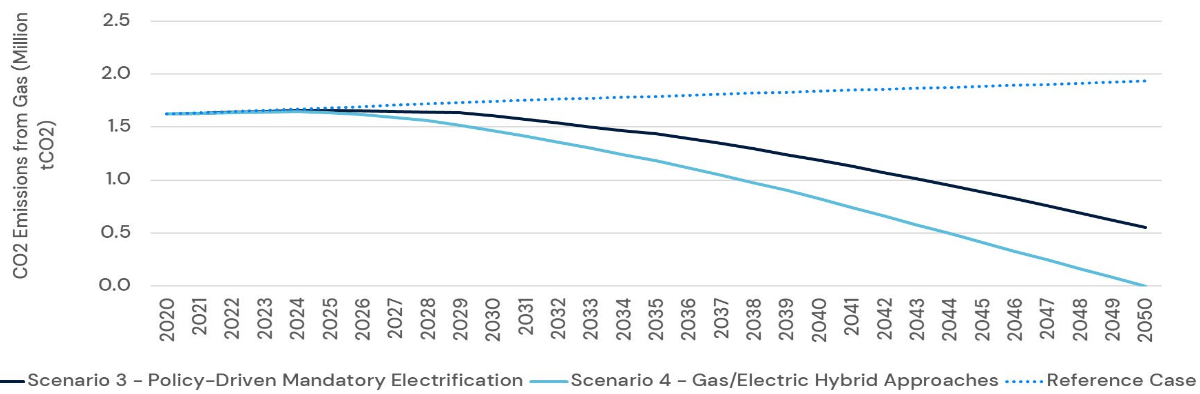


Table 56 summarizes the results of the residential and commercial customer scenario modeling. The natural gas decarbonization approaches (Scenarios 1 and 2) have the lowest consumer costs and the lowest emission reduction cost ($/tonne). The Hybrid Gas-Electric Technologies / RNG (Scenario 4) approach achieves the greatest GHG emission reduction, with the RNG available from sources considered here getting this scenario all the way to net-zero.

Table 56 - Summary of All VNG Scenario Results

	2020	Scenario 1	Scenario 2	Scenario 3	Scenario 4
	Base Year	Conventional Efficiency Options/ RNG	High Efficiency Gas Technologies/ RNG	Policy-Driven Mandatory Electrification	Hybrid Gas/Electric Technologies/ RNG
2050 Gas Consumption (Million MMBtu)	31	30	25	10	20
2050 Reduction in Gas Consumption vs. 2020 Base Year (%)		-3%	-17%	-66%	-35%
2050 Reduction in Gas Consumption vs. 2050 Reference Case (%)		-19%	-31%	-71%	-45%

2050 GHG Emissions (MMt CO_2 / year)	1.62	0.40	0.17	0.55	0.00
2050 Reduction in GHG Emissions vs. 2020 Base Year (%)		-75%	-90%	-66%	-100%
2050 Reduction in GHG Emissions vs. 2050 Reference Case (%)		-79%	-91%	-71%	-100%
Total Costs - NPV of Equipment and 2020-2080 Incremental Energy Costs ($2020 Millions)		$7,125	$9,408	$21,570	$17,409
NPV of GHG Emission Reductions (MMt CO_2)		22	25	19	28
Emission Reduction Costs ($/t$CO_2$)		$325	$374	$1,149	$633

Figure 87 shows the key results graphically. The Policy-Driven Mandatory Electrification scenario has the highest cost to consumers but the lowest reduction in GHG emissions, resulting in a cost of reduction three times as high in $/tonne GHG reduced than the High Efficiency Gas scenario.

Figure 87 – VNG Scenario Cost and Reduction Comparison

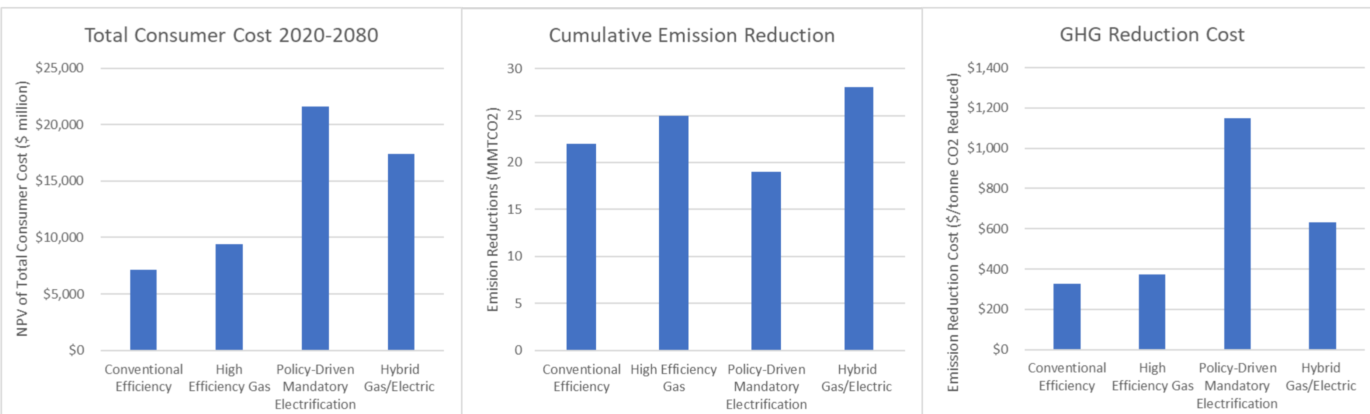


Table 57 shows the emission reduction cost by the various customer segments for new and existing building types. The gas technologies typically have the lowest cost due primarily to the deep reductions achieved through high efficiency and GHG-neutral RNG. For scenarios 2, 3, and 4, higher emission reduction costs for new buildings (vs. existing buildings) reflect the cost increase to build 'net-zero ready' buildings with a lower thermal load, while the savings from such measures are only captured out to 2080 (and even then savings from the latter years are discounted by more years than the incremental home purchase cost). Scenario 1 includes more modest building shell improvements for new construction.

Table 57 – VNG GHG Reduction Cost ($/tonne CO_2e)

Customer type	Vintage	$ Per Metric Ton of CO_2 2020-2080 (Discounted)			
		Scenario 1	Scenario 2	Scenario 3	Scenario 4
Single Family	**All vintages**	$186	$196	$212	$153
Single Family	New	$213	$311	$373	$284
Single Family	Existing	$179	$163	$175	$115
Multi-family	**All vintages**	$268	$260	$489	$216
Multi-family	New	$255	$295	$513	$254
Multi-family	Existing	$272	$249	$483	$204
Small Commercial	**All vintages**	$488	$575	$2,350	$707
Small Commercial	New	$698	$862	$2,948	$909
Small Commercial	Existing	$382	$428	$2,014	$607
Large Commercial	**All vintages**	$619	$760	$4,180	$1,772
Large Commercial	New	$872	$1,105	$5,317	$2,260
Large Commercial	Existing	$460	$541	$3,522	$1,466
Institutional	**All vintages**	$328	$390	$1,537	$814
Institutional	New	$390	$514	$1,885	$1,018
Institutional	Existing	$290	$312	$1,332	$686

12.6 Decarbonization Pathways for VNG

Figure 88 illustrates a potential decarbonization pathway for the VNG methane emissions. Baseline methane emissions can be expected to increase as VNG adds new customers with meters, service lines, mains and with dig-ins, blowdowns, etc. The customer growth rate is as described for the customer emission modeling in Section 5.1, resulting in an increase of 5% over 2019 in 2030 and 11% over 2019 in 2050. The largest reductions from the baseline emissions are completion of pipeline replacement programs, expanded LDAR, improved quantification of methane emissions from meters, and improved quantification of dig-in emissions. Despite the growth, the mitigation measures result in an estimated 53% reduction in methane emissions by 2030 including estimates of system growth. The remaining methane emissions would be offset with methane capture offsets from RNG projects both inside and outside the VNG service territory, resulting in net zero methane emissions in 2030 and continuing through 2050. The majority of the offsets would need to be acquired from outside the service territory due to the limited supply in the service territory.

Figure 88 – VNG Methane Emissions Reduction Pathway (1000 Mt CO_2e)

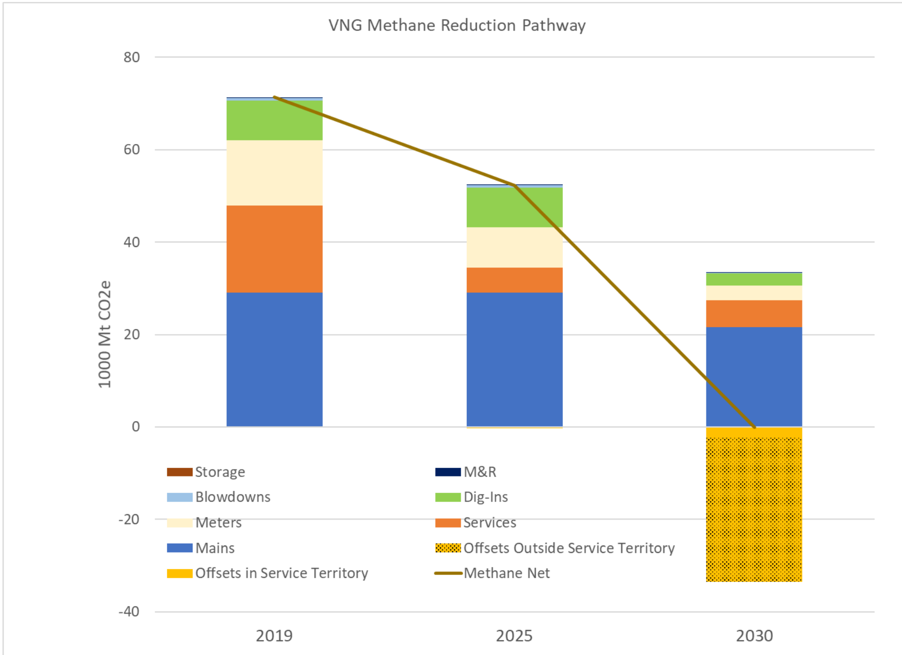
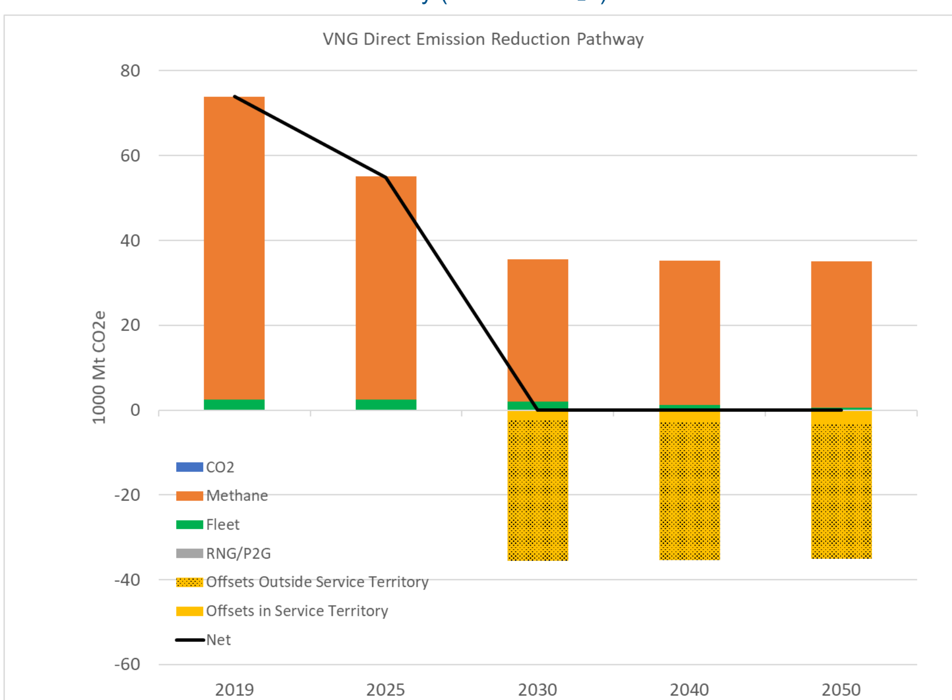


Figure 89 shows the reduction pathway for direct emissions. Other than RNG, the mitigation measure for CO_2 from fleet operations would be use of offsets. Because the RNG component for vehicles is not defined at this time, it was assumed that offsets are used for all fleet emissions. Figure 89 shows that methane remains the largest component of direct emissions and methane capture offsets remain an important measure for achieving net zero emissions through 2050.

Figure 89 - VNG Direct Emissions Reduction Pathway (1000 Mt CO_2e)

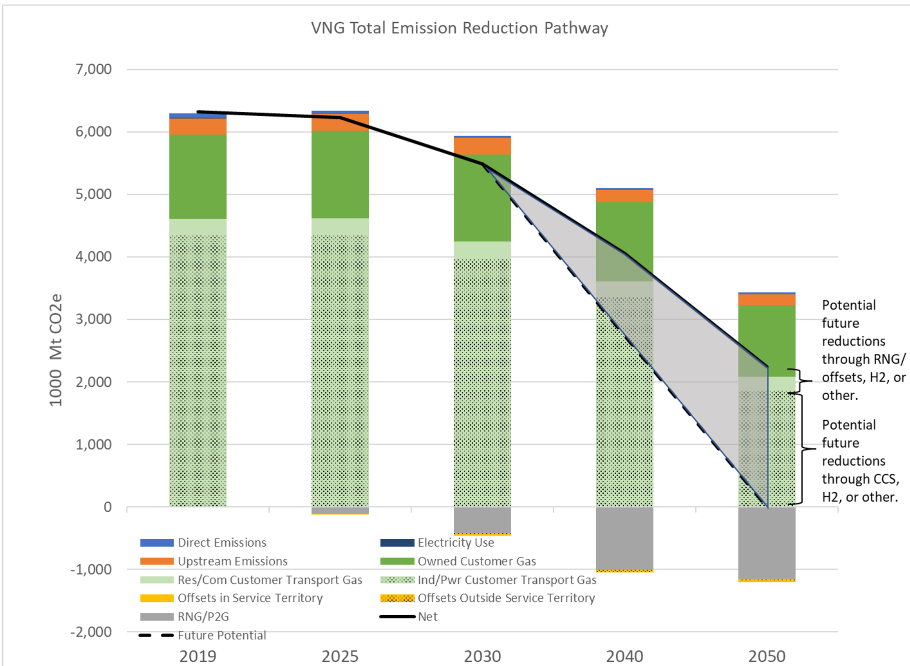


The VNG indirect GHG emissions include:

- Generation emissions for electricity that is used in-house by VNG.
- Upstream emissions for production, processing, and transportation of gas that is owned and sold by VNG.
- Emissions from customer use of gas.

As discussed earlier and shown in Figure 90, emissions from the customer use of gas are by far the largest source of direct or indirect emissions. As noted above, this pathway analysis includes emissions from all of VNG's customers' use of gas, which is beyond VNG's Scope 3 emissions under applicable GHG protocols, which only include gas owned and sold by VNG.

Figure 90 - VNG Total Emission Reduction Pathway (1000 Mt CO_2e)



The direct and indirect emissions were projected to be reduced by 46% from 2019 to 2050. Using the High Utilization Deployment estimate of RNG, P2G, and offset availability, VNG is projected to be net zero in 2050 for 88% of direct emissions, upstream emissions, and combustion emissions from gas owned and sold by VNG with resources inside the VNG service territory and some additional offsets from outside the service territory. This results in a 65% estimated reduction in net emissions from 2019 to 2050. The remaining emissions could potentially be reduced or offset through opportunities like hydrogen, RNG, combined heat and power, offsets from other sources, or use of carbon capture and sequestration.

13 Chattanooga Gas Company (CGC)

13.1 CGC Overview

Chattanooga Gas Company (CGC) serves customers in south central Tennessee. CGC provides gas delivery service to almost 67,000 customers. Most of the customers purchase both the delivery service and gas commodity itself from the Company as bundled sales service. Some industrial customers purchase only the delivery service from CGC and rely on another supplier for the gas commodity. Table 58, Figure 91 and Figure 92 summarize the distribution of customers and deliveries by customer segment and separate those customer segments by customers who take bundled commodity and delivery service (identified as "sales" customers) and customers who receive only delivery service from CGC (identified as "transportation" customers). (Sales for vehicle use are included in the commercial category.)

Residential customers made up 87% of the customers in 2019. Residential customers were smaller consumers on an Mcf/customer basis, accounting for only 22% of total deliveries. Most of the remaining customers were commercial sales customers, who consumed about 20% of deliveries. The industrial customers made up less than 1% of the number of customers but 57% of the total consumption. The industrial customers were roughly evenly split between sales and transportation customers, but the transportation customers consumed 94% of the industrial gas deliveries. This could be important if CGC offers alternative low GHG fuels, such as renewable natural gas (RNG) or hydrogen to its sales customers. Although CGC has a role to play in supporting the deployment of these alternative GHG fuels and promoting the development of RNG projects, these efforts will require partnership among CGC, the suppliers, and their transportation customers. There were no electric generating customers.

Figure 91 - CGC Customer Distribution – 2019 (1000)

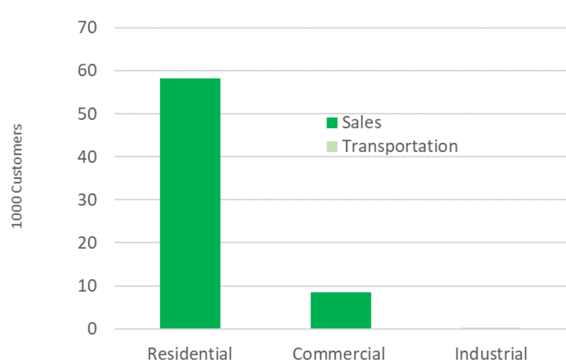


Figure 92 - CGC Delivery Distribution – 2019 (MMcf)

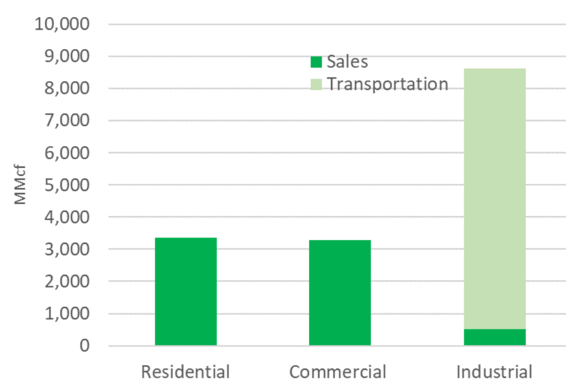


Table 58 - CGC Sales and Deliveries -2019

		Residential	Commercial	Industrial	Total
Sales	Customers	58,230	8,489	110	66,829
	Consumption (Mcf)	3,352,733	3,276,921	507,224	7,136,878
	Mcf/Customer	58	386	4,611	5,055
Transportation	Customers	0	0	113	113
	Consumption (Mcf)	0	0	8,126,288	8,126,288
	Mcf/Customer			71,914	71,914
Total	Customers	58,230	8,489	223	66,942

	Consumption (Mcf)	3,352,733	3,276,921	8,633,512	15,263,166

13.2 CGC Emissions

The direct emissions totaled 21 1000 Mt CO_2e. The largest component was methane emissions from the distribution operations. That said, CGC estimates that it has reduced annual methane emissions from its distribution system from 1998 to 2018 by over 50% — even as the system grew by approximately 20%. CO_2 emissions from storage facility operation, primarily compressor fuel use, were the second largest component. CO_2 emissions fleet vehicles were much smaller.

Figure 93 - CGC Direct GHG Emissions - 2019 (1000 Mt CO2e)

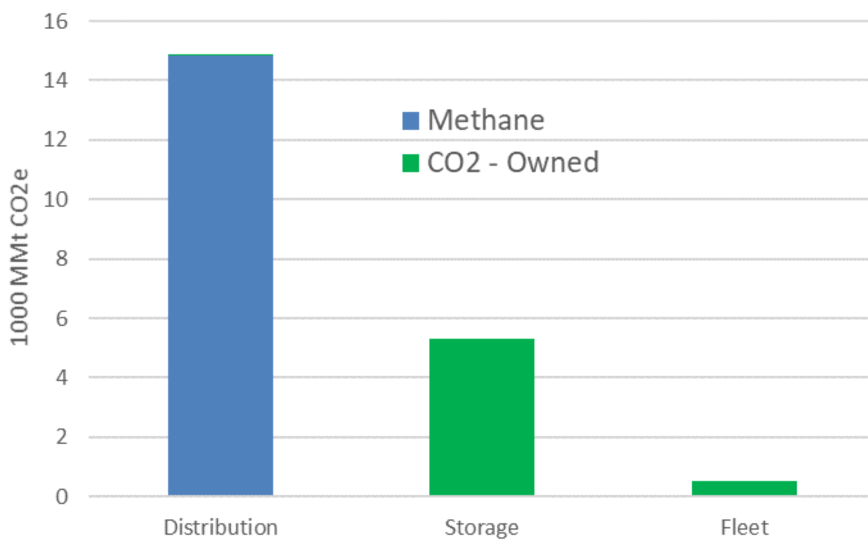


Figure 94 and Table 59 show that indirect emissions related to customer gas use were much larger than any of the other sources. Roughly 50% of the customer emissions were from gas owned and sold by CGC versus gas purchased from other sources by industrial customers. The company-owned indirect emissions were 441 1000 Mt CO_2e while the not owned emissions were 442 1000 Mt CO_2e. CGC's total direct and indirect emissions including the gas owned and sold by CGC accounted for 0.4% of the estimated Tennessee GHG emissions in 2019. The upstream emissions shown include only those related to gas owned and sold by CGC because CGC does not control and cannot track the emissions from gas provided by other entities.

Figure 94 - CGC Direct and Indirect Emissions - 2019 (1000 Mt CO2e)

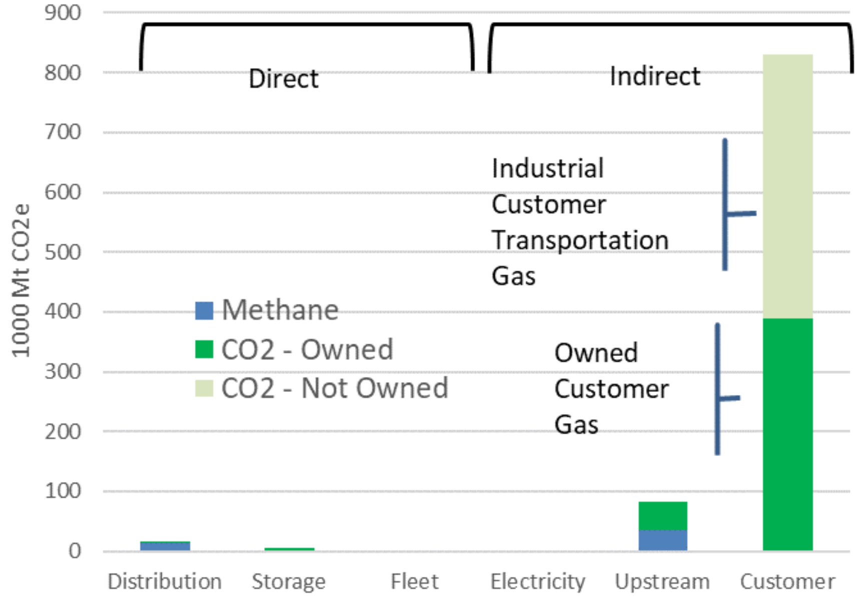
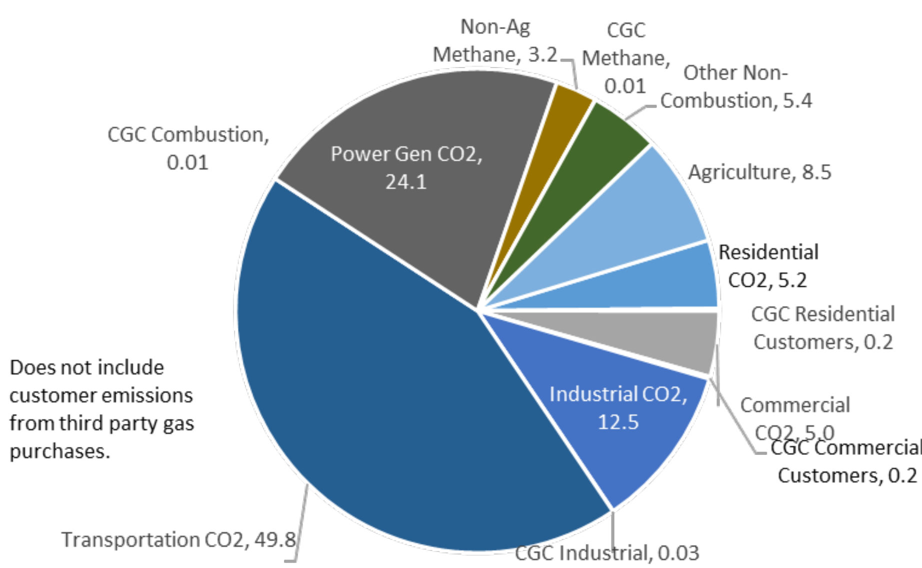


Table 59 - CGC Direct and Indirect GHG Emissions - 2019 (1000 Mt CO2e)

	Direct Emissions			Indirect Emissions			Total
	Distribution	Storage	Fleet	Electricity	Upstream	Customer	
Methane	14.8	<0.1			36.4		**51.3**
Owned CO_2	<0.1	5.2	0.5	0.3	46.4	388.2	**440.8**
Not Owned CO_2						442.1	**442.0**
Total	**14.8**	**5.2**	**0.5**	**0.3**	**82.8**	**830.3**	**934.1**

Figure 95 shows the CGC emissions in the context of the estimated Tennessee state GHG inventory.

Figure 95 - Estimated Tennessee and CGC GHG Emissions - 2019 (MMt CO2e)



13.3 RNG for CGC

Table 60 summarizes the maximum RNG potential for each biomass-based feedstock and production technology by geography of interest, reported in million cubic feet (MMcf). The RNG potential includes different variables for each feedstock, but ultimately reflects the most favorable options available, such as the highest biomass price and the utilization of all feedstocks at all facilities. The estimates included in these tables are based on the maximum RNG production potential from all feedstocks, and do not apply any economic or technical constraints on feedstock availability. An assessment of resource availability is addressed in Section 3.3, which also includes a comparison of these volumes to deliveries of conventional gas.

Table 60 - Technical Potential for CGC RNG Production by Feedstock (MMcf/y)

RNG Feedstock	CGC	Rest of TN	Total
Animal Manure	521	26,326	26,847
Food Waste	132	1,776	1,908
Landfill Gas	1,046	18,667	19,713
Water Resource Recovery Facilities	189	1,613	1,802
Anaerobic Digestion Sub-Total	*1,887*	*48,383*	*50,270*
Agricultural Residue	7	21,447	21,454
Energy Crops	2,380	233,101	235,481
Forestry & Forest Product Residue	289	12,971	13,260
Municipal Solid Waste	1,165	15,665	16,830
Thermal Gasification Sub-Total	*3,841*	*283,184*	*287,025*
Total	5,728	331,567	337,295

ICF developed economic supply curves for three separate scenarios for each feedstock. The RNG potential included in the supply curves is based on an assessment of resource availability. In a competitive market, that resource availability is a function of multiple factors, including but not limited to demand, feedstock costs, technological development, accessibility to pipeline connections, and the policies in place that might support RNG project development. ICF assessed the RNG resource potential of the different feedstocks that could be realized, given the necessary market considerations (without explicitly defining what those are).

Table 61 - Projected Annual RNG Production in CGC Service Territory by 2050 (MMcf/yr)

RNG Feedstock		Scenario		
		Limited Adoption	Moderate Deployment	High Utilization Deployment
Anaerobic Digestion	Animal Manure	42	83	151
	Food Waste	50	73	97
	LFG	111	168	222
	WRRFs	81	135	190
Thermal Gasification	Agricultural Residue	0	0	0
	Energy Crops	51	717	1,115
	Forestry and Forest Product Residue	87	145	203
	Municipal Solid Waste	130	447	582
Total		551	1,768	2,560

Figure 96 - Growth Scenarios for Annual RNG Production in CGC Service Territory (MMcf/yr)

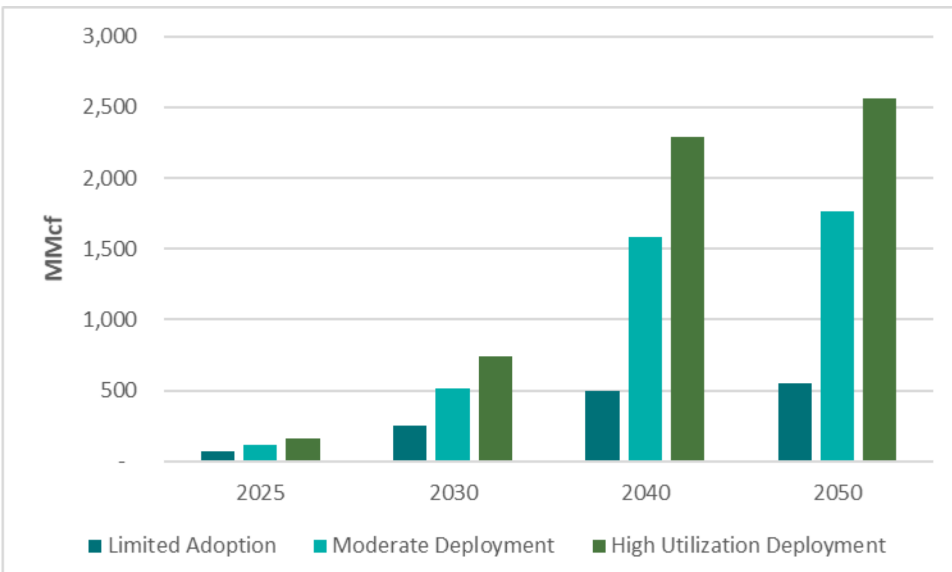


Figure 97 - P2G Production Scenarios for CGC (MMcf/yr)

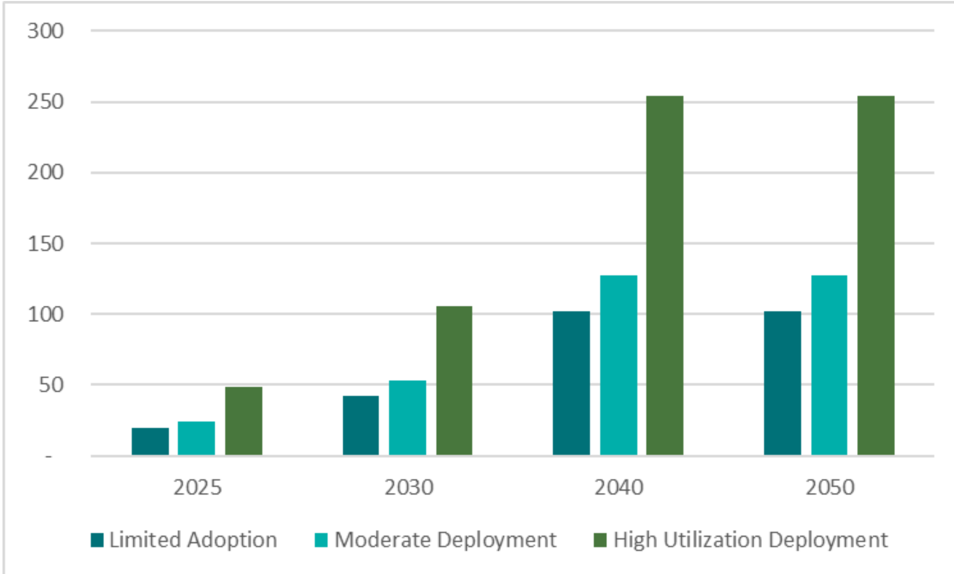


Figure 98 and Figure 99 present the RNG/P2G potential in the context of the CGC gas deliveries. The left two bars show the gas deliveries in 2019 and potential deliveries in 2050 with the implementation of energy efficiency measures as in Scenario 2 discussed in Section 5.1. The three bars on the right side show the total amount of RNG/P2G and gas equivalent of offsets that are projected to be available in 2030, 2040, and 2050 in each of the three growth RNG scenarios. This does not include consumption of these resources for other uses than customer demand (i.e., offsetting direct emissions), which is addressed in the pathway analysis in Section 7. Figure 76 shows the breakout of the RNG, P2G, and offset equivalent gas volume in the High Utilization Deployment case.

Figure 98 – RNG Potential vs CGC Gas Deliveries by Supply Case (MMcf/yr)

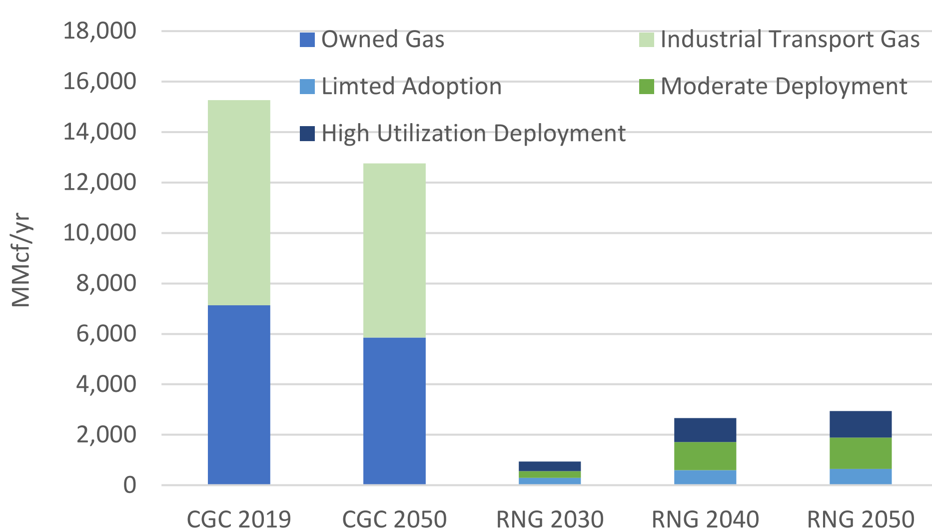


Figure 99 – RNG Potential vs CGC Gas Deliveries by Supply Type (MMcf/yr)

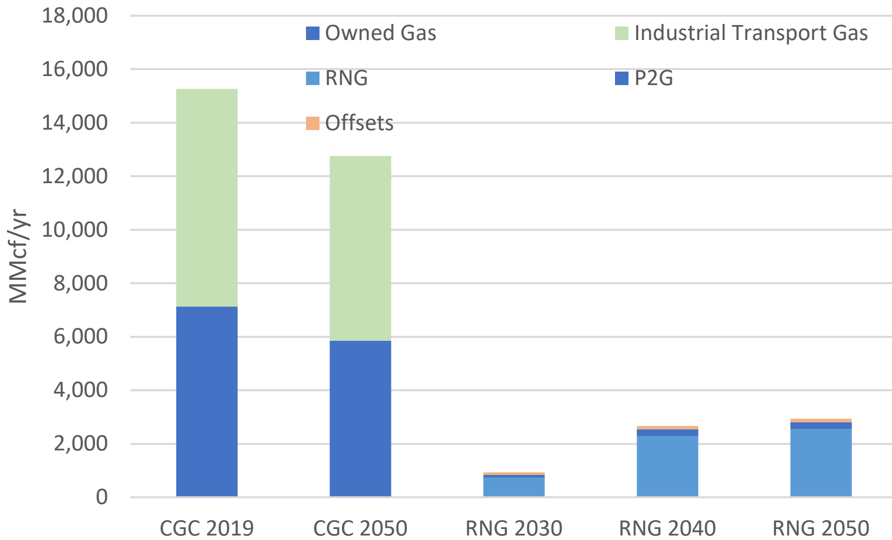
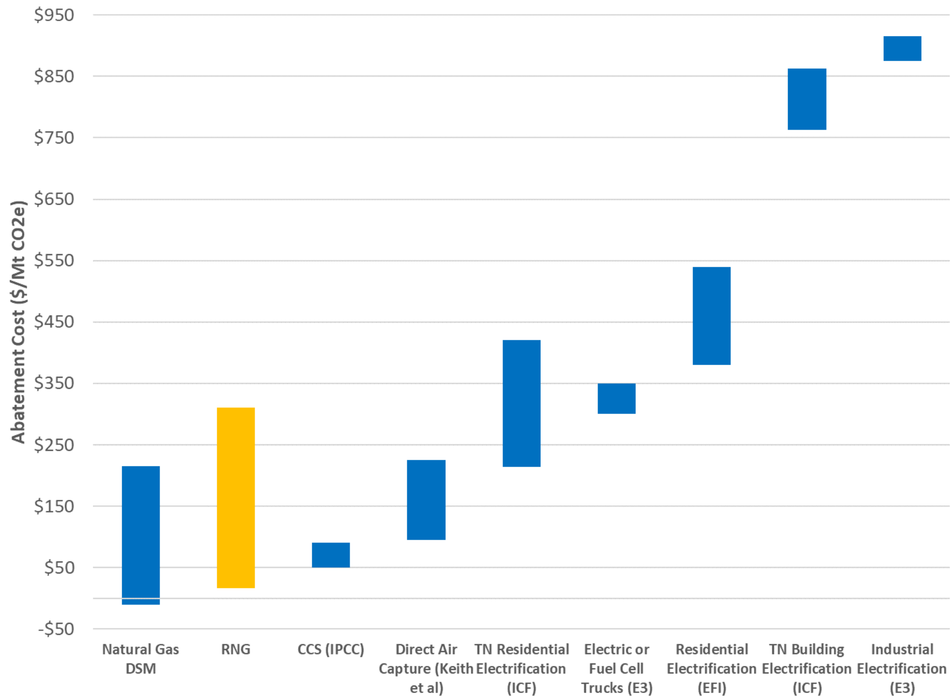


Figure 100 shows a comparison of selected decarbonization measures across various key studies for specific abatement measures that are likely to be required for economy-wide decarbonization in the 2050 timeframe, including natural gas demand side management (DSM),[66] RNG (from this study), carbon capture and storage (CCS),[67] direct air capture (whereby CO_2 is captured directly from the air and a concentrated stream is sequestered or used for beneficial purposes),[68] battery electric trucks (including fuel cell drivetrains),[69] and policy-driven electrification of certain end uses (including buildings and in the industrial sectors).[70,]

[66] See Con Edison's Smart Usage Rewards program (https://www.coned.com/en/save-money/rebates-incentives-tax-credits/smart-usage-rewards-for-reducing-gas-demand) and National Grid's Demand Response Pilot program (https://www.nationalgridus.com/GDR).
[67] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.).
[68] Keith, DW; Holmes, G; St Angelo D; Heidel, K; A Process for Capturing CO_2 from the Atmosphere, *Joule*, 2 (8), p1573-1594. https://doi.org/10.1016/j.joule.2018.05.006
[69] E3, 2018. Deep Decarbonization in a High Renewables Future, https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization
[70] Energy Futures Initiative (EFI), 2019. Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California, https://energyfuturesinitiative.org/efi-reports.

Figure 100 - GHG Abatement Costs, Selected Measures ($/Mt CO_2e)



13.4 Direct Emission Reductions

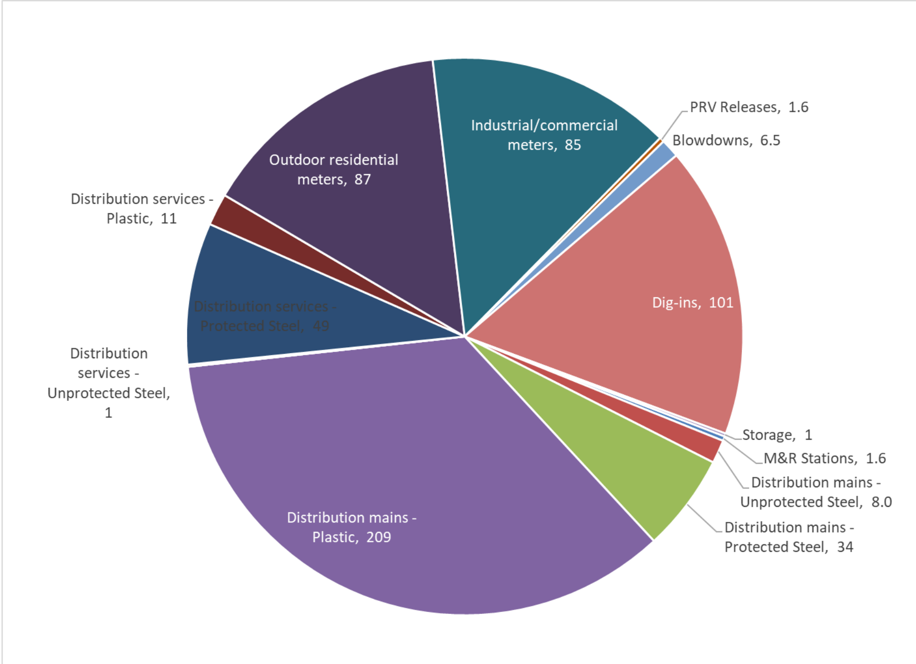
Table 62shows the breakdown of the methane emissions for CGC, which totaled 594 Mt CH_4 in 2019 or 14.9 1000 Mt CO_2e when weighted by the GWP. Three components accounted for 98% of the emissions. Customer meters comprised 29%, distribution mains and services comprised 52%, and dig-ins (damage to mains and services from construction) comprised 17%.

Table 62 summarizes the potential reduction in estimated methane emissions for the CGC LDC and storage facilities. The largest reductions are from enhanced LDAR and monitoring of meters, followed by completion of pipeline replacement. The total potential reduction is 25%.

Table 62 - Summary of CGC Potential Methane Reductions (Mt CH_4)

	Pipes	Meters	Dig-Ins	Blowdowns	M&R Stations	LDC Total	Storage	Total
Baseline	311	172	101	6	3.2	593	1	594
Reductions	8	137	0.0	4	0.4	151	-	151
Remaining	303	34	101	2	2.8	442	1	443

Figure 101 - CGC Methane Emissions 2019 (Mt CH_4)



Beyond methane emissions, there are CO_2 emissions. The majority, 91%, of CGC's CO_2 emissions are from the gas-fired compressors and electricity generators at its storage facilities. There are three options to address these emissions:

- Fueling the compressors and generators with GHG-neutral RNG. This would require 96,400 Mcf of RNG per year.
- Offsetting the emissions with methane capture from RNG production. This would require 5.2 1000 Mt CO_2e of methane capture offsets.
- Replacing the gas-fired compressors with electric compressors. This would require a significant capital investment. A simple replacement project could cost in the range of $10 to $15 million based on a similar project described in the EPA Natural Gas STAR program.[71] However the company estimates that including electricity upgrades and support systems and auxiliaries could increase costs to as much as $30 million per compressor. If the replacement is part of the normal equipment turnover schedule, the incremental cost could be lower. A more detailed analysis would be required for a more accurate cost estimate. Maintenance costs for electric compressors are typically lower than for gas-fired equipment. On the other hand, storage facilities must be available to operate at all times, especially during winter conditions when electric outages may be more likely. Electrification would require installation of back-up generators to ensure reliability, which could add significantly to the cost. Electrification would eliminate direct emissions but increase indirect emissions related to electricity consumption. The indirect emissions would decline over time if and when grid emissions are reduced. The larger storage facilities have multiple compressors so it could be possible to implement multiple solutions (i.e., RNG and electrification) and/or phase them in over time.

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[71] https://www.epa.gov/natural-gas-star-program/install-electric-compressors

13.5 Indirect Emission Reductions

Table 63 summarizes the technology penetration in the CGC gas scenarios. The measures are installed gradually through requirements for new construction and stock turnover in existing buildings. The implementation of gas heat pumps is more gradual due to the newness of the technology.

Table 63 - Technology Penetration in CGC Gas Scenarios

Scenario 1 – Conventional Efficiency Options/RNG	Scenario 2 – High Efficiency Gas Technology/RNG
Implementation begins in 2025 Almost 80% of customers install high efficiency gas furnaces or boilers by 2050 35% of buildings get air sealing and add attic insulation by 2050	Implementation begins in 2025 Natural gas heat pumps start being adopted in 2025 and reach 54% of single family homes, 29% of multi-family, 38% of commercial buildings by 2050 30% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic insulation

Table 64 summarizes the results of the gas scenarios. The two scenarios are compared to a reference case in which gas demand continues to grow from current levels by about 20% through 2050 based on growth forecasts from the U.S. EIA Annual Energy Outlook.[72] The scenarios result in a 19% reduction in direct fuel use in 2050 for Scenario 1 and 32% in Scenario 2 compared to the reference case. In addition to the increased efficiency, the scenarios substitute RNG for conventional natural gas. In Scenario 1, efficiency plus RNG was able to reduce customer CO_2 emissions by 54% in 2050. In Scenario 2, efficiency plus RNG fully replaces conventional gas, resulting in a 67% reduction in CO_2 emissions from these customers in 2050. The table also shows the net present value cost of equipment installations through 2050 and incremental customer energy costs through 2080. (Energy costs through 2080 are included in order to include the operating costs of equipment installed in 2050 over a reasonable time period using that equipment.) The net present value of emission reductions through 2080 is then calculated in order to calculate an emission reduction cost in \$/tonne CO_2 reduced. The emission reduction cost is \$279/tonne CO_2 reduced for Scenario 1 and \$321/tonne for Scenario 2 across all residential and commercial customers.

[72] https://www.eia.gov/outlooks/aeo/

Table 64 - Summary of CGC Gas Scenario Results

	2020 Base Year	Scenario 1 Conventional Efficiency Options/RNG	Scenario 2 High Efficiency Gas Technologies/ RNG
2050 Gas Consumption (Million MMBtu)	7	7	6
2050 Reduction in Gas Consumption vs. 2020 Base Year (%)		-3%	-18%
2050 Reduction in Gas Consumption vs. 2050 Reference Case (%)		-19%	-32%
2050 GHG Emissions (MMt CO_2 / year)	0.37	0.20	0.15
2050 Reduction in GHG Emissions vs. 2020 Base Year (%)		-45%	-60%
2050 Reduction in GHG Emissions vs. 2050 Reference Case (%)		-54%	-67%
Total Costs - NPV of Equipment and 2020-2080 Incremental Energy Costs ($2020 Millions)		973	1,363
NPV of GHG Emission Reductions (MMt CO_2)		3	4
Emission Reduction Costs ($/t$CO_2$)		$ 279	$ 321

The figures below provide additional context for the annual impacts for residential and commercial CGC customers out to 2050, which drive the results showcased in the above Scenario Summary. Figure 102 shows the overall reduction in CGC residential and commercial natural gas demand out to 2050.

Figure 102 – Annual Gas Demand (Trillion Btu)

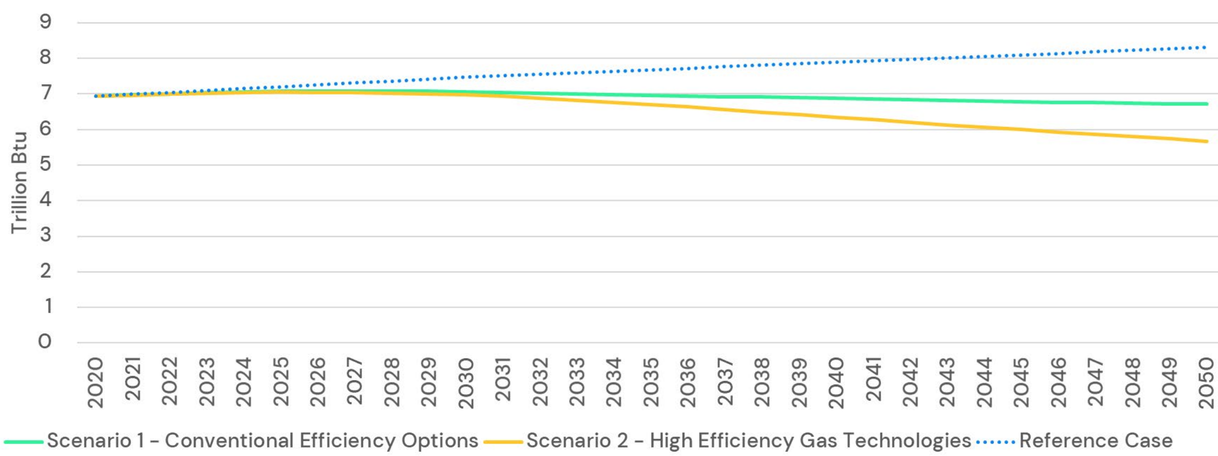


Figure 103 shows the total increase in energy costs from the gas scenarios, including the incremental upfront costs to install higher efficiency equipment and better insulate homes, changes in the energy costs to customers (based on reference case natural gas rates and the reduction in natural gas consumption), and incremental costs to purchase decarbonized gases (RNG and P2G). Figure 104 provides additional context on the make-up of those changes in customer energy costs.

Figure 103 – CGC Total Annual Costs - Equipment Installations and Incremental Energy Costs) ($Millions)

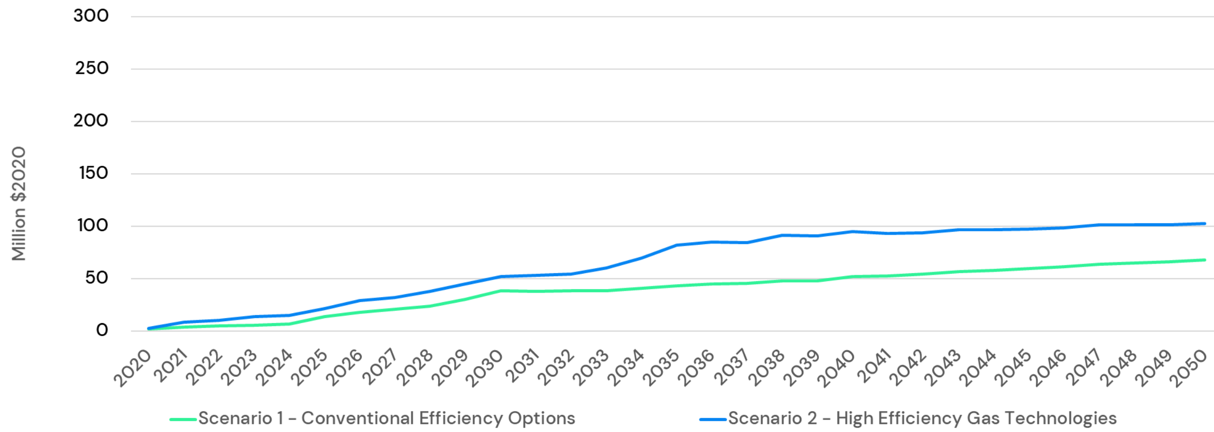


Figure 104 – CGC Incremental Annual Energy Costs ($Millions)

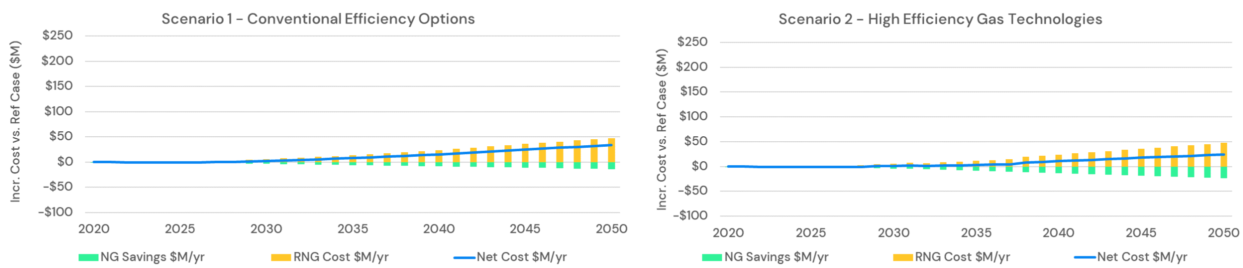


Figure 105 shows the emission reduction pathways for both of these scenarios. If RNG was not included in these scenarios, and no other changes were made, the GHG emission reductions would be reduced, matching gas demand reductions from Figure 79, but the emission reductions costs ($/tCO$_2$) would also be lower.

Figure 105 – CGC CO_2 Emissions from Natural Gas (Million tCO_2)

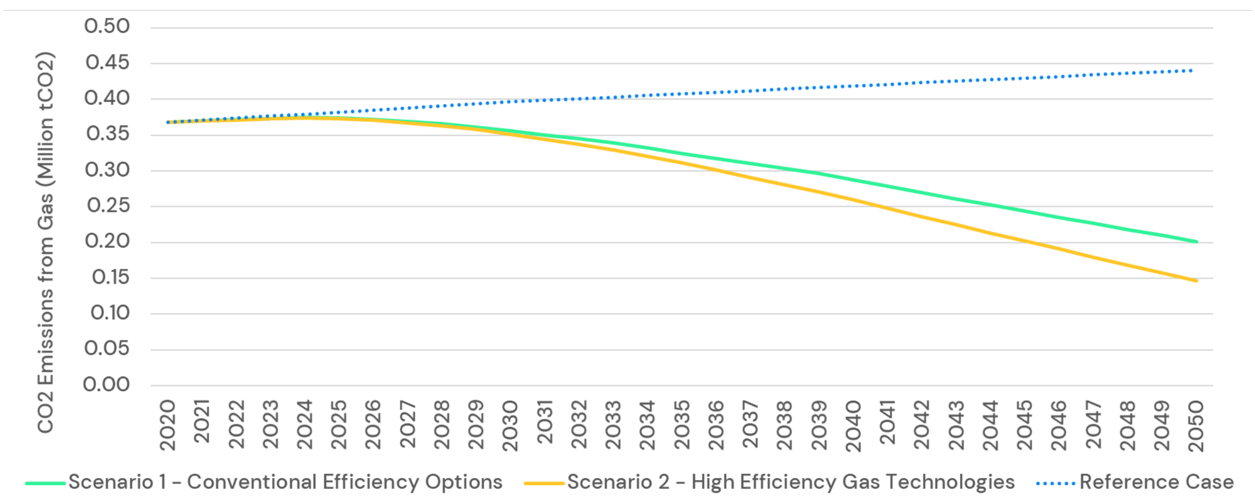


Table 65 summarizes the technology penetration assumptions for the electrification scenarios. Mandatory policies are assumed to require electrification for all new construction starting in 2025 and for all replacement/retrofits starting in 2030. The all-electric share of single family homes reaches 90% of single family homes by 2050.

Table 65 - Technology Penetration in CGC Electricity Scenarios

Scenario 3 – Policy-Driven Mandatory Electrification	Scenario 4 – Gas/Electric Hybrid Technology/RNG
Mandatory all-electric for new construction as of 2025. Mandatory conversion to electric space and water heating starting in 2030 when replacing equipment. All-electric share reaches 90% in single family homes and 77% in commercial by 2050. Mix of ASHPs and electric resistance. 30% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic insulation	Starting in 2023 air-conditioning units get replaced with Air-Source Heat Pumps, forming hybrid-heating systems with the existing gas furnace. By 2050 hybrid heating reaches 76% of single family homes and 73% of commercial. 30% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic insulation

The two scenarios are compared to a reference case in which gas demand continues to grow from current levels by about 20% through 2050 based on growth forecasts from the U.S. EIA Annual Energy Outlook. The scenarios result in a reduction of direct fuel use in 2050 by 72% for Scenario 3 and 47% in Scenario 4, compared to the reference case in 2050. In addition to the electrification and efficiency improvements, Scenario 4 also meets the remaining gas demand with RNG (no RNG is used in Scenario 3). In Scenario 3, mandatory electrification and energy efficiency do not fully eliminate natural gas demand by 2050 because not all gas heating equipment is replaced and there are some non-heating/water heating gas applications that remain, resulting in a 72% reduction in natural gas CO_2 emissions from residential and commercial customers relative to the reference case. In Scenario 4, targeted electrification, energy efficiency, plus RNG reduce customer CO_2 emissions by 82%. The table also shows the net present value of equipment installations through 2050 and incremental customer energy costs through 2080. (Energy costs through 2080 are included in order to include the operating costs of equipment installed in 2050 over a reasonable period of time using that equipment.)

Table 66 - Summary of Electric Scenario Results

	2020	Scenario 3	Scenario 4
	Base Year	Policy-Driven Mandatory Electrification	Hybrid Gas/Electric Technologies
2050 Gas Consumption (Million MMBtu)	7	2	4
2050 Reduction in Gas Consumption vs. 2020 Base Year (%)		-67%	-36%
2050 Reduction in Gas Consumption vs. 2050 Reference Case (%)		-72%	-47%
2050 GHG Emissions (MMt CO_2 / year)	0.37	0.12	0.08
2050 Reduction in GHG Emissions vs. 2020 Base Year (%)		-67%	-78%
2050 Reduction in GHG Emissions vs. 2050 Reference Case (%)		-72%	-82%

Total Costs - NPV of Equipment and 2020-2080 Incremental Energy Costs ($2020 Millions)		3,512	2,543
NPV of GHG Emission Reductions (MMt CO_2)		4	5
Emission Reduction Costs ($/t$CO_2$)		$ 814	$ 493

Customer energy costs include changes in:

- Natural gas costs (based on reference case natural gas rates and the reduction in natural gas consumption),
- Costs for the additional electricity needed for electrified equipment (based on reference case electricity rates and the cost adders shown in Table 21),
- Cost increases on baseline electricity consumption (original customer electric load, less efficiency improvements, not including the newly electrified portion) for CGC customers from the increase in electric rates assumed to be driven by the changes in these scenarios (based on the cost adders shown in Table 21, but showing just the cost increase incremental to changes that would occur for scenario 1 and 2 based on their respective adders; for example scenario 3 is based on impact for CGC customers if electric rates went up 3.5 cents/kWh, while scenario 4 is based on a rate increase of 0.5 cents/kWh), and
- Incremental costs to purchase decarbonized gases (RNG and P2G for Scenario 4 only).

The net present value of emission reductions through 2080 is then calculated in order to calculate an emission reduction cost in $/tonne CO2 reduced. The emission reduction cost is $814/tonne CO_2 reduced for Scenario 3 and $493/tonne for Scenario 4, across all residential and commercial customers (there are differences in costs by customer types, with higher costs for commercial buildings). The targeted electrification with greater fuel flexibility assumed in Scenario 4 has a lower cost than the broader electrification requirement assumed in Scenario 3, as well as the value of continuing to leverage the gas distribution system to meet peak winter heating energy demand on the coldest days of the year. That said, it could have significant impacts on gas system operations and cost that are not included in this model, as discussed above.

The figures below provide additional context on the annual impacts for residential and commercial CGC customers out to 2050, which drive the results summarized in the Scenario Summary. Figure 106 shows the overall reduction in CGC residential and commercial natural gas demand out to 2050.

Figure 106 – CGC Annual Gas Demand (Trillion Btu)

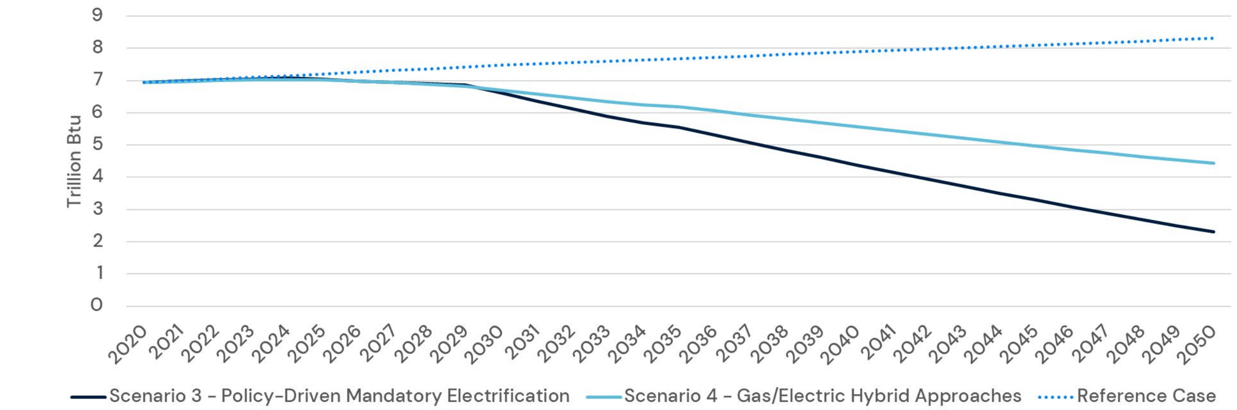


Figure 107 shows the total increase in energy costs from the electrification scenarios, including the incremental upfront costs to install higher efficiency equipment, electric equipment, or better insulate homes, and changes in the energy costs to customers.

Figure 107 – CGC Total Annual Costs - Equipment Installations and Incremental Energy Costs ($Millions)

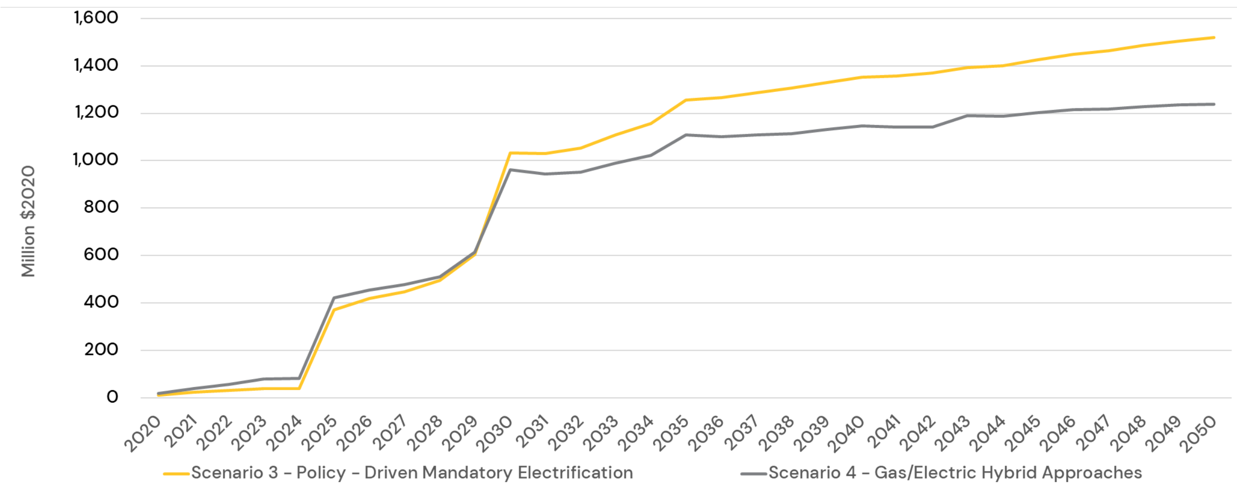


Figure 108 provides additional detail on the make-up of the changes in customer energy costs discussed above.

Figure 108 – CGC Incremental Annual Energy Costs ($Millions)

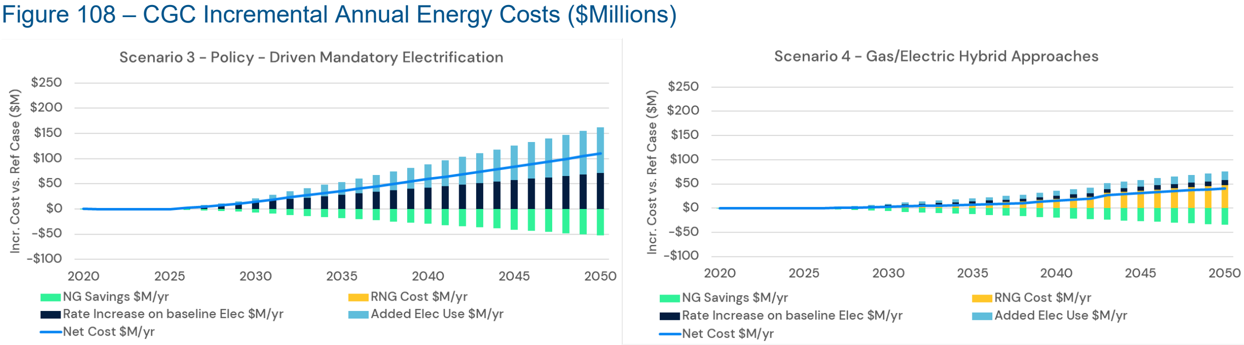


Figure 109 shows the emission reduction pathways for both of these scenarios. The use of RNG in the Gas/Electric Hybrid Scenario results in larger emission reductions by 2050 than the Policy-Driven Mandatory Electrification Scenario analyzed here.

Figure 109 – CGC CO_2 Emissions from Natural Gas ($MMtCO_2$)

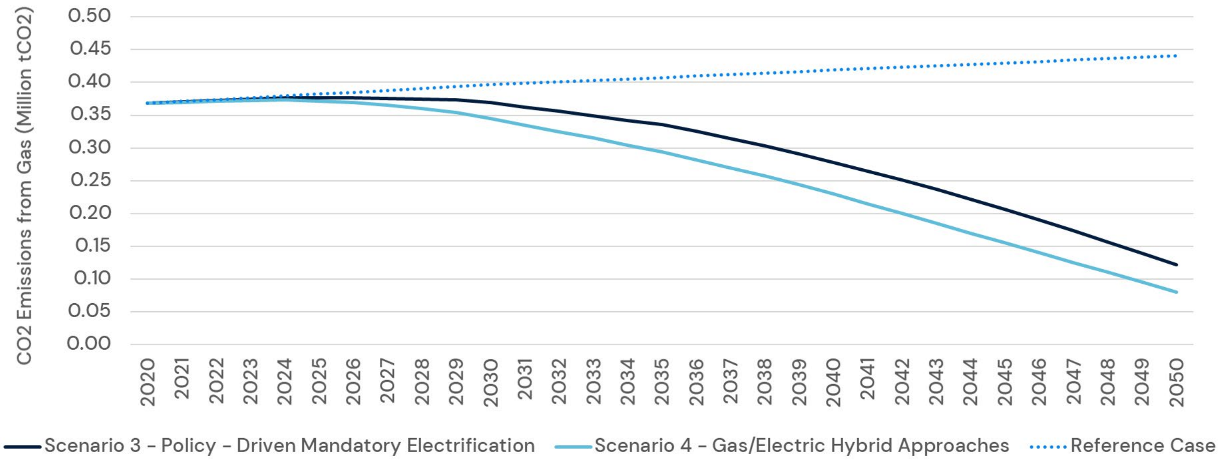


Table 67 summarizes the results of the residential and commercial customer scenario modeling. The natural gas decarbonization approaches (Scenarios 1 and 2) have the lowest consumer costs and the lowest emission reduction cost ($/tonne). The Hybrid Gas-Electric Technologies / RNG (Scenario 4) approach achieves the greatest GHG emission reduction, with the RNG available from sources considered here getting this scenario all the way to net-zero.

Table 67 - Summary of All CGC Scenario Results

	2020	Scenario 1	Scenario 2	Scenario 3	Scenario 4
	Base Year	Conventional Efficiency Options/ RNG	High Efficiency Gas Technologies/ RNG	Policy-Driven Mandatory Electrification	Hybrid Gas/Electric Technologies/ RNG
2050 Gas Consumption (Million MMBtu)	7	7	6	2	4
2050 Reduction in Gas Consumption vs. 2020 Base Year (%)		-3%	-18%	-67%	-36%
2050 Reduction in Gas Consumption vs. 2050 Reference Case (%)		-19%	-32%	-72%	-47%
2050 GHG Emissions (MMt CO_2 / year)	0.37	0.20	0.15	0.12	0.08
2050 Reduction in GHG Emissions vs. 2020 Base Year (%)		-45%	-60%	-67%	-78%
2050 Reduction in GHG Emissions vs. 2050 Reference Case (%)		-54%	-67%	-72%	-82%
Total Costs - NPV of Equipment and 2020-2080 Incremental Energy Costs ($2020 Millions)		973	1,363	3,512	2,543
NPV of GHG Emission Reductions (MMt CO_2)		3	4	4	5
Emission Reduction Costs ($/t$CO_2$)		$ 279	$ 321	$ 814	$ 493

Figure 110 shows the key results graphically. The Policy-Driven Mandatory Electrification scenario has the highest cost to consumers but the lowest reduction in GHG emissions, resulting in a cost of reduction more than twice as high in $/tonne GHG reduced than the High Efficiency Gas scenario.

Figure 110 – CGC Scenario Cost and Reduction Comparison

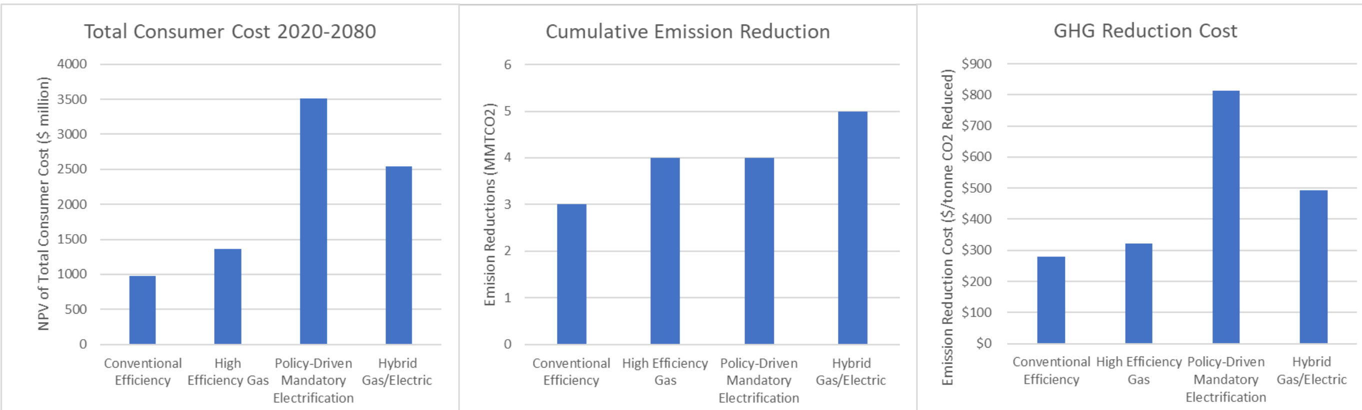


Table 68 shows the emission reduction cost by the various customer segments for new and existing building types. The gas technologies typically have the lowest cost due primarily to the deep reductions achieved through high efficiency and GHG-neutral RNG. For scenarios 2, 3, and 4, higher emission reduction costs for new buildings (vs. existing buildings) reflect the cost increase to build 'net-zero ready' buildings with a lower thermal load, while the savings from such measures are only captured out to 2080 (and even then savings from the latter years are discounted by more years than the incremental home purchase cost). Scenario 1 includes more modest building shell improvements for new construction.

Table 68 – CGC GHG Reduction Cost ($/tonne CO_2e)

Customer type	Vintage	$ Per Metric Ton of CO_2 2020-2080 (Discounted)			
		Scenario 1	Scenario 2	Scenario 3	Scenario 4
Single Family	**All vintages**	**$162**	**$197**	**$251**	**$164**
Single Family	New	$205	$348	$418	$316
Single Family	Existing	$149	$152	$214	$121
Multi-family	**All vintages**	**$189**	**$171**	**$403**	**$163**
Multi-family	New	$234	$224	$421	$197
Multi-family	Existing	$177	$155	$399	$153
Small Commercial	**All vintages**	**$403**	**$450**	**$1,137**	**$516**
Small Commercial	New	$523	$608	$1,351	$616
Small Commercial	Existing	$334	$358	$1,017	$463
Large Commercial	**All vintages**	**$679**	**$831**	**$3,402**	**$1,850**
Large Commercial	New	$959	$1,186	$4,255	$2,315
Large Commercial	Existing	$492	$586	$2,909	$1,548
Institutional	**All vintages**	**$261**	**$295**	**$1,001**	**$585**
Institutional	New	$299	$364	$1,140	$700
Institutional	Existing	$237	$247	$919	$509

13.6 Decarbonization Pathways for CGC

Figure 111 illustrates a potential decarbonization pathway for the CGC methane emissions. Baseline methane emissions can be expected to increase as CGC adds new customers with meters, service lines, mains and with dig-ins, blowdowns, etc. The customer growth rate is as described for the customer emission modeling in Section 5.1, resulting in an increase of 5% over 2019 in 2030 and 9% over 2019 in 2050. Despite the growth, the mitigation measures result in an estimated 24% reduction in methane emissions by 2030. The largest reductions from the baseline emissions are completion of pipeline replacement programs and expanded LDAR/improved quantification of methane emissions from meters. The remaining methane emissions would be offset with methane capture offsets from RNG projects both inside and outside the CGC service territory, resulting in net zero methane emissions in 2030 and continuing through 2050. About one third of the methane capture offsets would need to be acquired from outside the service territory due to the limited supply in the service territory.

Figure 111 - Methane Emissions Reduction Pathway (1000 Mt CO_2e)

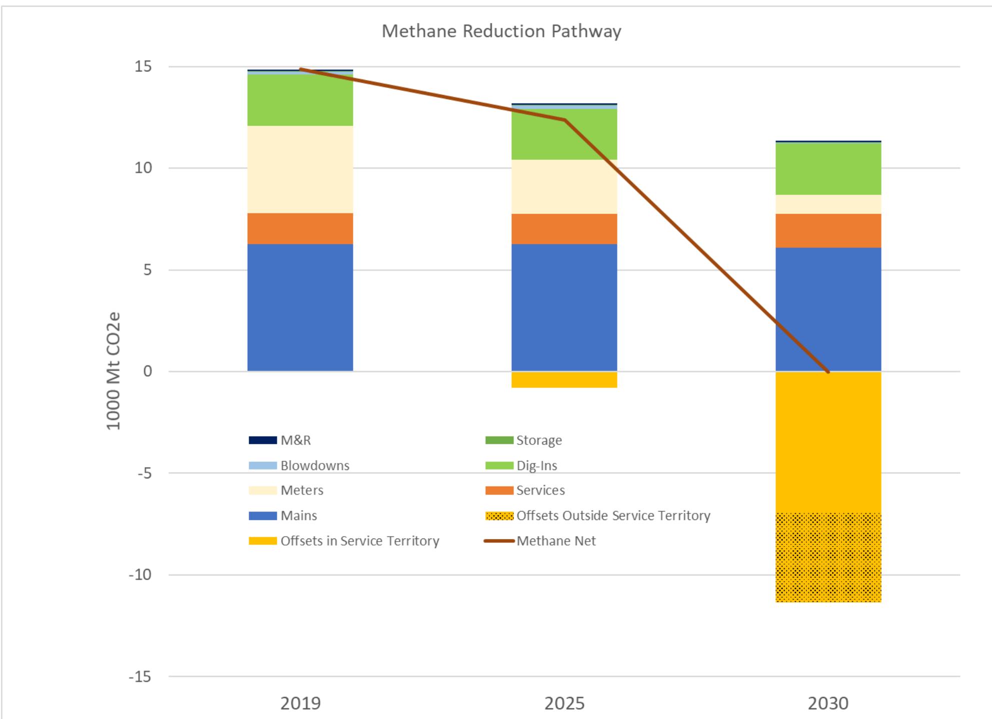
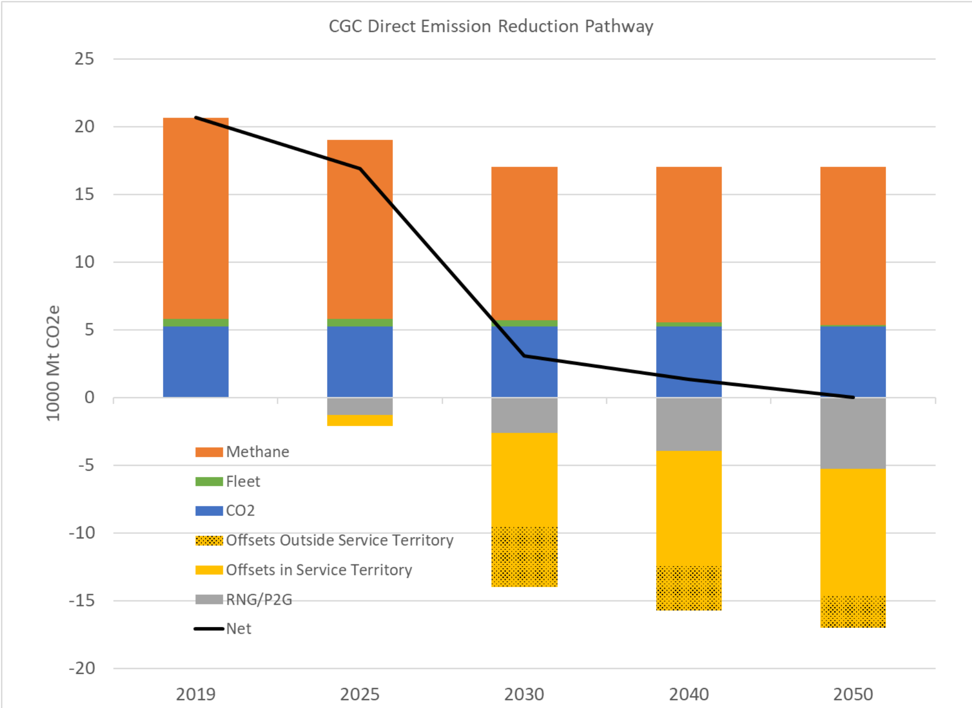


Figure 112 shows the reduction pathway for direct emissions including CO_2 from storage facilities and fleet operations. The storage-related emissions are assumed to be achieved through use of RNG. Figure 112 shows that methane remains the largest component of direct emissions and methane capture offsets remain an important measure for achieving net zero emissions through 2050.

Figure 112 - CGC Direct Emissions Reduction Pathway (1000 Mt CO_2e)



The CGC indirect GHG emissions include:

- Generation emissions for electricity that is used in-house by CGC.
- Upstream emissions for production, processing, and transportation of gas that is owned and sold by CGC.
- Emissions from customer use of gas.

As discussed earlier and shown in Figure 113, emissions from the customer use of gas are by far the largest source of direct or indirect emissions. As noted above, this pathway analysis includes emissions from all of CGC's customers' use of gas, which is beyond CGC's Scope 3 emissions under applicable GHG protocols, which only include gas owned and sold by CGC.

The direct and indirect emissions were projected to be reduced by 17% from 2019 to 2050. Using the High Utilization Deployment estimate of RNG, P2G, and offset availability, CGC was projected to be net zero in 2050 for 43% of direct emissions, upstream emissions, and combustion emissions from gas owned and sold by CGC with resources inside the CGC service territory and some additional methane capture offsets from outside the service territory. This results in a 35% estimated reduction in net emissions from 2019 to 2050. The remaining emissions could potentially be reduced or offset through opportunities like hydrogen, RNG, combined heat and power, offsets from other sources, or use of carbon capture and sequestration.

Figure 113 - CGC Total Emission Reduction Pathway (1000 Mt CO_2e)