Decarbonization Pathways for Virginia Natural Gas

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Southern Company Gas

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List of Abbreviations

AGA	American Gas Association
AGF	American Gas Foundation
ASHP	Air Source Heat Pump
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
HPWH	Heat Pump Water Heater
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
SCC	Virginia State Corporation Commision
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

VNG Plays an Important Role in the Southeastern Virginia Energy Economy

Virginia Natural Gas (VNG) is the natural gas local distribution company (LDC) located primarily in the Hampton Roads region of southeastern Virginia, serving over 300,000 customers including 12 critical national defense facilities, electric generators, and major employers in the region. VNG's natural gas infrastructure is a highly reliable and resilient system that delivers energy at half to one fifth the price of electricity.[1]

VNG Can Play a Key Role in Decarbonizing the Virginia Economy

VNG 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 state, especially customer emissions from gas consumption. This study did not attempt to optimize the overall emission reduction strategy for the Commonwealth of Virginia. Rather it presents different emission reduction pathways and strategies through which VNG can contribute to cost-effective reduction of Virginia GHG emissions from its own operations, from its customers, and from other segments of the Virginia economy, and also provide other benefits to its customers.

In addition, Southern Company has committed to achieve net zero direct greenhouse gas (GHG) emissions from its enterprise-wide operations by 2050, which is inclusive of the operations of its subsidiary Southern Company Gas, VNG's parent company.

VNG specified the following tenets to be included in evaluating options for a decarbonization pathway for the utility.

- Reduction or offset of 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 natural gas GHG reduction pathway is consistent with all of these tenets. The gas-based GHG reduction pathways identified in this analysis, if realized, would achieve net zero GHG emissions from operations by 2050 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

[1] Energy cost and delivery data from U.S. EIA. See Table 15.

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.

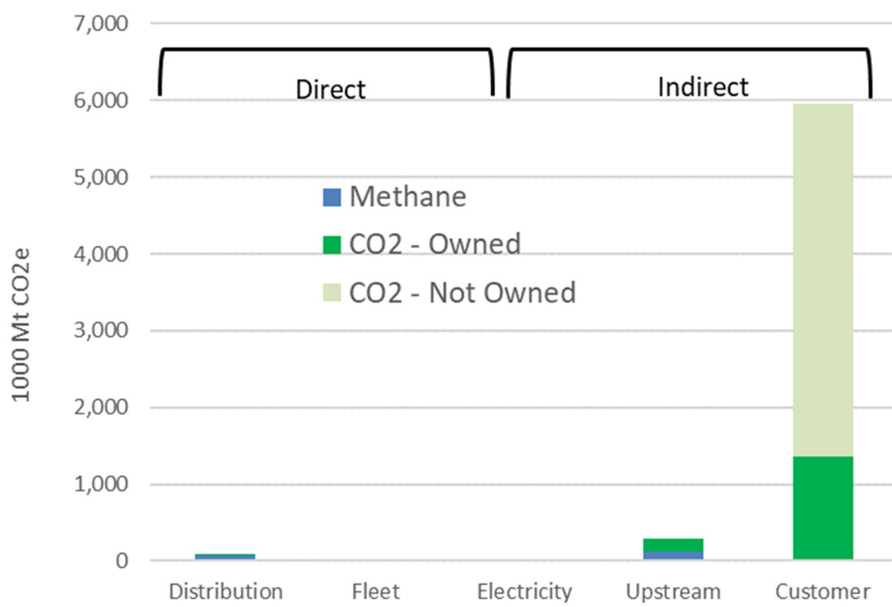
The natural gas infrastructure also offers the opportunity to incorporate future low-GHG energy sources such as renewable natural gas and hydrogen. This study indicates that decarbonizing the existing natural gas system and improving the efficiency of the end use gas equipment owned by customers could be a faster, less expensive pathway to reducing Virginia 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.

VNG's Direct Emissions are a Very Small Part of the Virginia GHG Inventory

VNG's direct GHG emissions include the following:

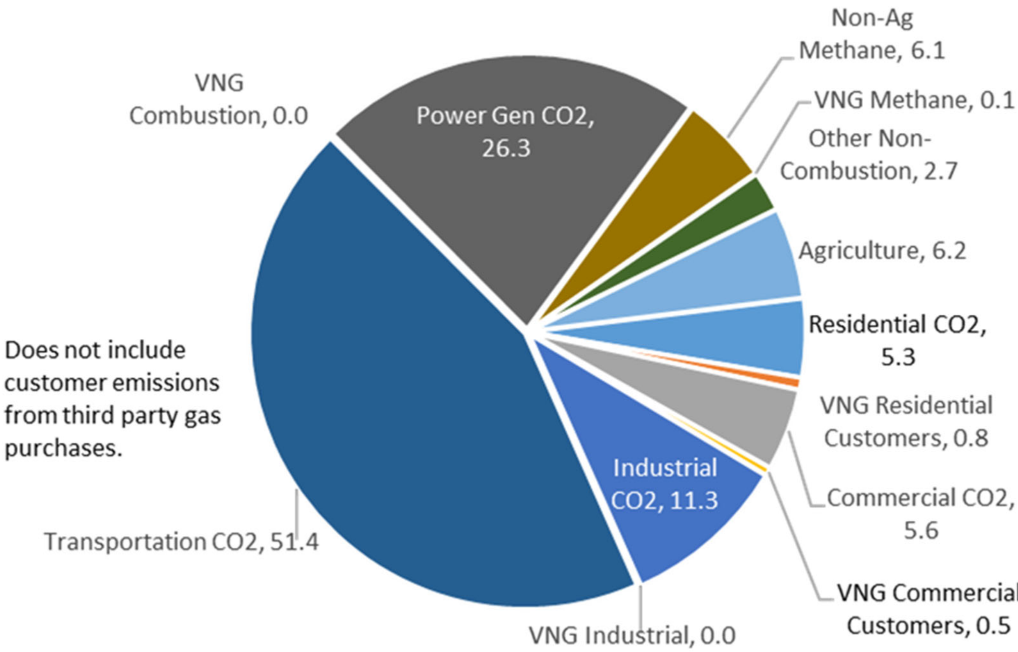
- Fugitive and vented methane emissions from operations at the distribution facilities.
- CO_2 emissions from combustion at distribution operations and fleet vehicles.

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



The direct emissions totaled 74 thousand Mt CO_2e in 2019. The largest component was methane emissions from the distribution operations. That said, 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%. The CO_2 emissions from vehicle fleets is a much smaller component. VNG's total direct GHG emissions were less than 0.1% of the estimated total Virginia GHG emissions in 2019. The direct methane emissions were less than 1% of the estimated Virginia methane emissions.

Estimated Virginia GHG Emissions and VNG Emissions – 2019 (MMt 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 VNG.
- Upstream emissions from the production, processing, and transportation of gas that is owned and sold by VNG.
- Emissions from customer use of gas delivered by VNG.

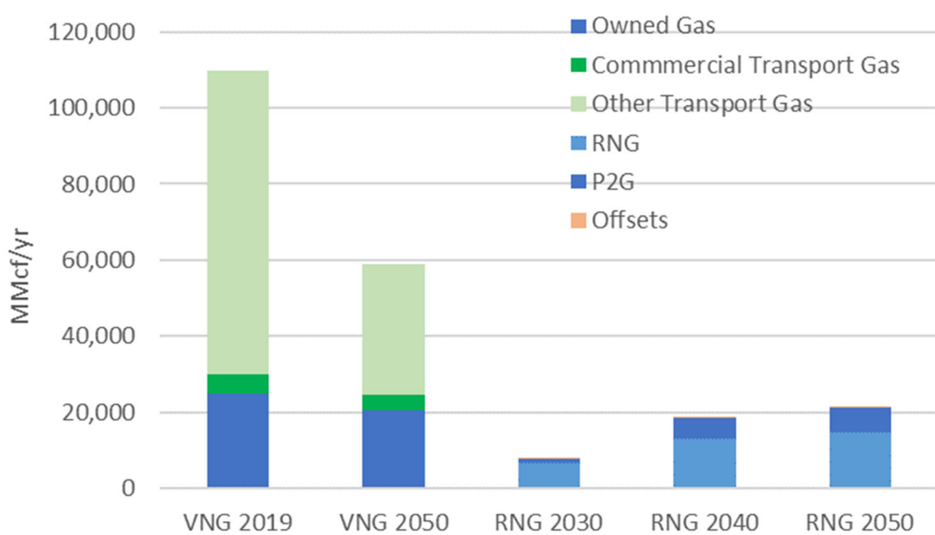
Emissions related to customer gas use were several orders of magnitude larger than any of the other sources, almost 6 million Mt CO_2e ($MMtCO_2e$) based on the total volume of gas delivered to customers as tabulated and reported to the U.S. Energy Information Administration on Form 176.[2] Roughly 20% of the customer emissions are from gas owned and sold by VNG versus gas purchased from other sources by customers and delivered by VNG including a large amount of gas delivered to electric generators. The total VNG emissions including gas owned and sold by VNG were 1.3% of the estimated total Virginia GHG emissions in 2019. The upstream emissions cited in this report only include gas owned and sold by VNG because VNG does not control and cannot track the emissions from gas provided by other entities.

[2] 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 it its reporting program. On the other hand, according to the current WRI/WBCSD GHG Protocol, VNG's Scope 3 emissions would be limited to the gas owned and sold by VNG, 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 VNG and identify opportunities to reduce those emissions, but also noted that there are more limited actual Scope 3 emissions.

Renewable Natural Gas Can Provide Environmental and Economic Benefits to VNG's 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, 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. The figure below shows the projected RNG supply compared to current VNG gas deliveries and projected 2050 deliveries under the high efficiency/advanced gas technology scenario discussed later in the report and with the High Utilization Deployment RNG scenario.

RNG Potential vs VNG Gas Deliveries by Supply Type – High Utilization Deployment RNG Case (MMcf/yr)



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 can avoid 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 and operations also create construction and operation jobs and secondary economic benefits, especially in the agricultural sector, which is Virginia's largest private industry sector.[3]

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,

[3] http://www.vdacs.virginia.gov/markets-and-finance-agriculture-facts-and-figures.shtml

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 VNG based on several renewable electricity scenarios, resulting in 2,600 to 6,500 MMcf per year of P2G by 2050.

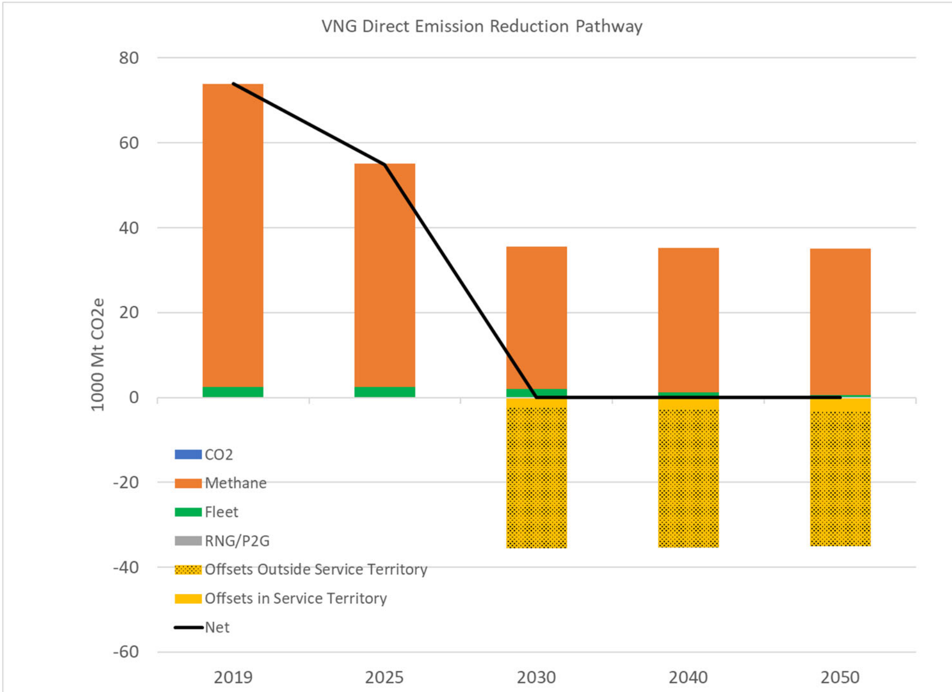
There is a Pathway for VNG to Achieve Net Zero Direct GHG Emissions

There are available and cost-effective options to reduce the methane emissions that comprise the largest source of VNG's 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 53% 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 VNG 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

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 achieves net zero methane emissions by 2030 and net zero for all direct GHG emissions by 2050.



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

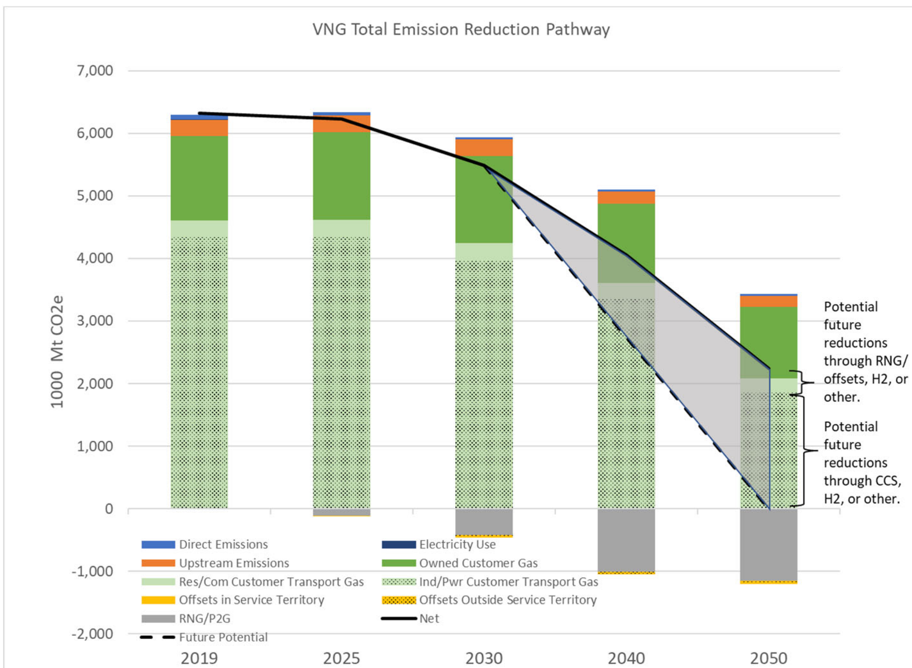
The largest source of indirect emissions was the emissions from customer use of gas. Indirect emissions from upstream methane emissions and CO_2 from combustion were much lower than the customer emissions. The upstream emissions could be addressed through the purchase of gas from entities who commit 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 - Implementation begins in 2030. Almost 80% of customers install high efficiency gas furnaces or boilers by 2050 with RNG. 35% of 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 and reach 54% of single family homes, 28% of multi-family, and 38% of commercial buildings by 2050. 30% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic insulation. RNG replaces natural gas by 2050.
- Scenario 3 – Policy-Driven Mandatory Electrification - All-electric equipment required for new construction as of 2025. Conversion to electric space and water heating required for replacements starting in 2030. All-electric share reaches 93% in single family homes and 87% in commercial buildings by 2050. 30% of buildings get deep energy retrofits by 2050, and 16% 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. By 2050, hybrid heating reaches 75% of single family homes

and 75% of commercial buildings. 30% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic. 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

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.



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. The RNG supply projected within the VNG service territory under the High Utilization Deployment RNG scenario allows for mitigation of nearly all of the customer emissions from gas owned and sold by VNG. The remaining emissions are primarily from large industrial and power generation customers who purchase their own gas supply. VNG could work with these customers to reduce their emissions through the use of hydrogen, RNG, combined heat and power, or offsets from other sources or use of carbon capture and sequestration.

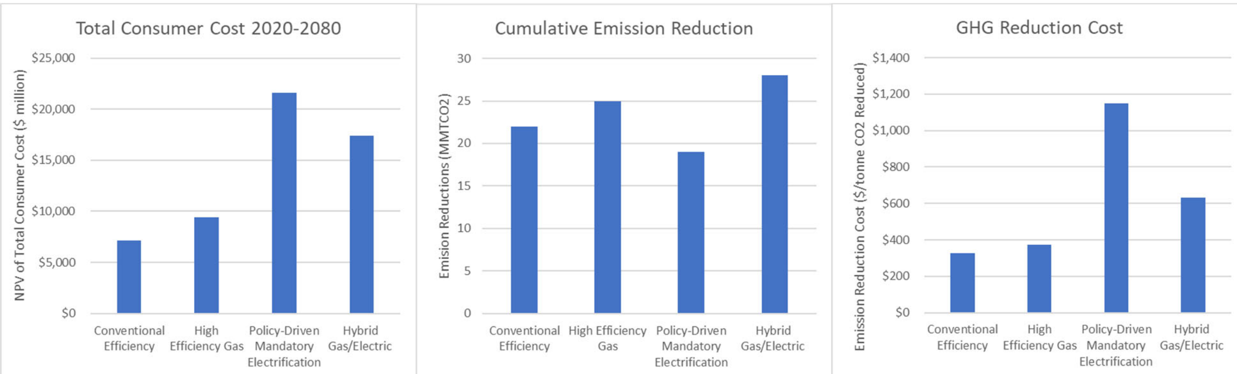
The Natural Gas Pathways Offer Additional Consumer Benefits

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 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 less than $400/tonne CO_2e, roughly one third that of the policy-driven, mandatory electrification scenario modeled here.

Summary of Scenario Results



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 Virginia and its 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

Virginia Natural Gas engaged ICF to analyze how it can develop a pathway for reduction of GHG emissions from its operations and also reduce other GHG emissions in the Commonwealth, especially customer emissions from gas consumption.

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.[4] 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.[5] 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 sources that Congress has revived via the Congressional Review Act.[6] 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

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[4] "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

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

[6] 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

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.[7] 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 parent company of Southern Company Gas and VNG, has set GHG emissions reduction goals across all electric and gas operations.[8] In addition to considering investments to reduce direct and indirect emissions, Southern Company Gas is exploring GHG-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 VNG's direct and indirect emissions, they will also reduce VNG's 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 cost than other decarbonization options modeled or reviewed in this study by taking advantage of the existing natural gas infrastructure in conjunction with energy efficiency, new technology, and CO_2-neutral gaseous fuels.

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[7] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf
[8] https://www.southerncompany.com/clean-energy/net-zero.html

2.2 Description of VNG and Operations

VNG serves customers in the southeastern, Hampton Roads region of Virginia. VNG provides gas delivery service to over 300,000 customers. Most customers purchase both the delivery service and the gas commodity itself from the Company as bundled sales service. Some commercial, industrial, electric generation customers purchase only the delivery service (transportation service) from VNG and rely on another supplier for the gas commodity. Table 1, Figure 1, and Figure 2 summarize the distribution of customers and deliveries by customer segment and separates those customer segments by customers who take bundled commodity and delivery service (identified as "sales" customers) and customers who receive only delivery service from VNG (identified as "transportation" customers). (Sales for vehicle use are included in the commercial category.)

Table 1 - VNG Customers 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 1 – VNG Customer Distribution – 2019 (1000)

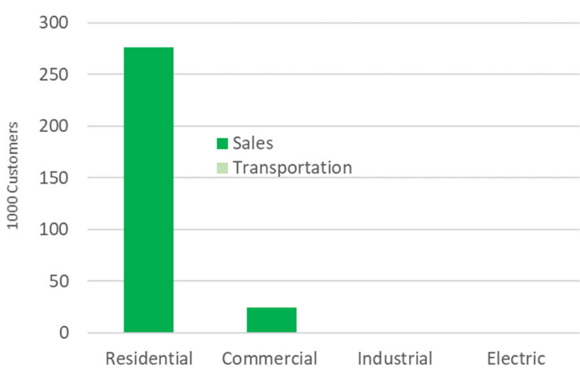
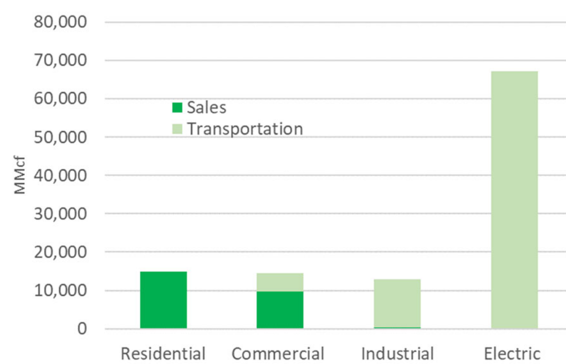


Figure 2 - VNG Delivery Distribution – 2019 (MMcf)



Residential customers made up 92% of the customers in 2019 and all of them purchased the gas commodity from VNG. Residential customers were 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 included 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 included 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 partnership among VNG, the suppliers, and their transportation customers. Transportation customers would have to look to their suppliers for these alternative fuels.

The study relied on several different sources and methodologies to estimate VNG's 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 VNG's business. These emissions are classified as Scope 3 according to the WRI/WBCSD GHG reporting protocol.[9] However, the WRI/WBCSD definition includes only gas that is owned and sold by the company 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 VNG's Scope 3 emissions, which would be limited to the gas owned and sold by VNG according to the current WRI/WBCSD GHG Protocol.

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, VNG's Scope 3 emissions would be limited to the gas owned and sold by VNG, 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 VNG and identify

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

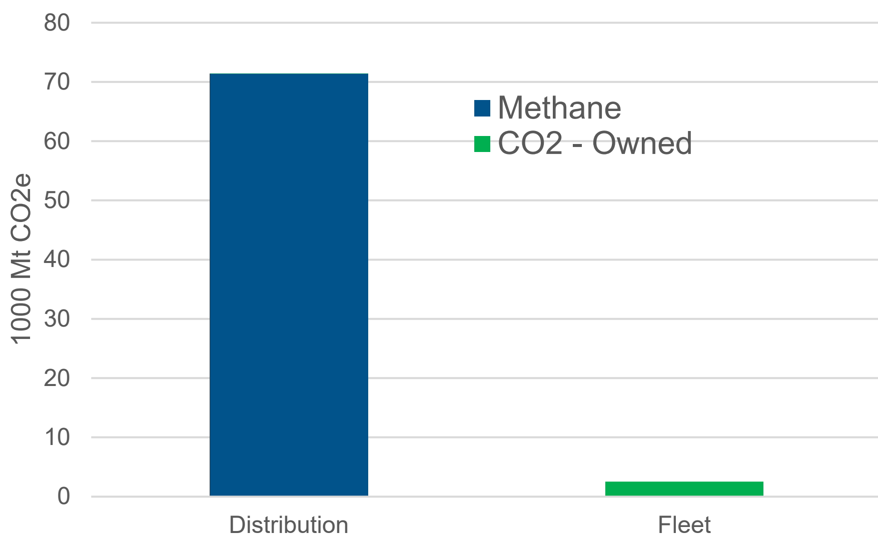
opportunities to reduce those emissions, but also noted that there are more limited actual Scope 3 emissions.

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.

VNG's 2019 direct greenhouse gas (GHG) emissions (Figure 3) included:

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

Figure 3 - VNG Direct GHG Emissions - 2019 (1000 Mt CO2e)



The direct emissions totaled 74 thousand metric tonnes of CO_2 equivalent (1000 Mt CO_2e). The largest component was methane emissions from the distribution operations. CO_2 emissions from distribution system operations and fleet vehicles were much smaller.

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 VNG.
- Upstream emissions from the production, processing, and transportation of gas that is owned and sold by VNG.
- Emissions from customer use of gas delivered by VNG. The emissions shown here are 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 VNG's Scope 3 emissions, which would be limited to the gas owned and sold by VNG under the current WRI/WBCSD GHG Protocol.

Figure 4 and Table 2 show that 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 include only gas owned and sold by VNG because VNG does not control and cannot track the emissions from gas provided by other entities.

Figure 4 - VNG Direct and Indirect Emissions - 2019 (1000 Mt CO2e)

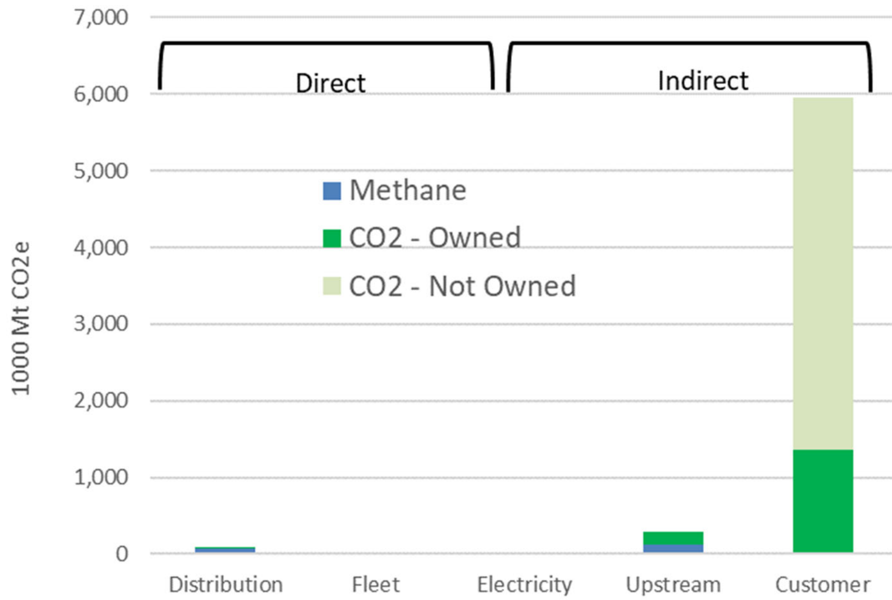


Table 2 - VNG Direct and Indirect GHG Emissions - 2019 (1000 Mt CO_2e)

	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**

Virginia does not have a comprehensive state GHG inventory to which to compare these emissions. However, ICF has assembled an estimated state inventory from several sources:

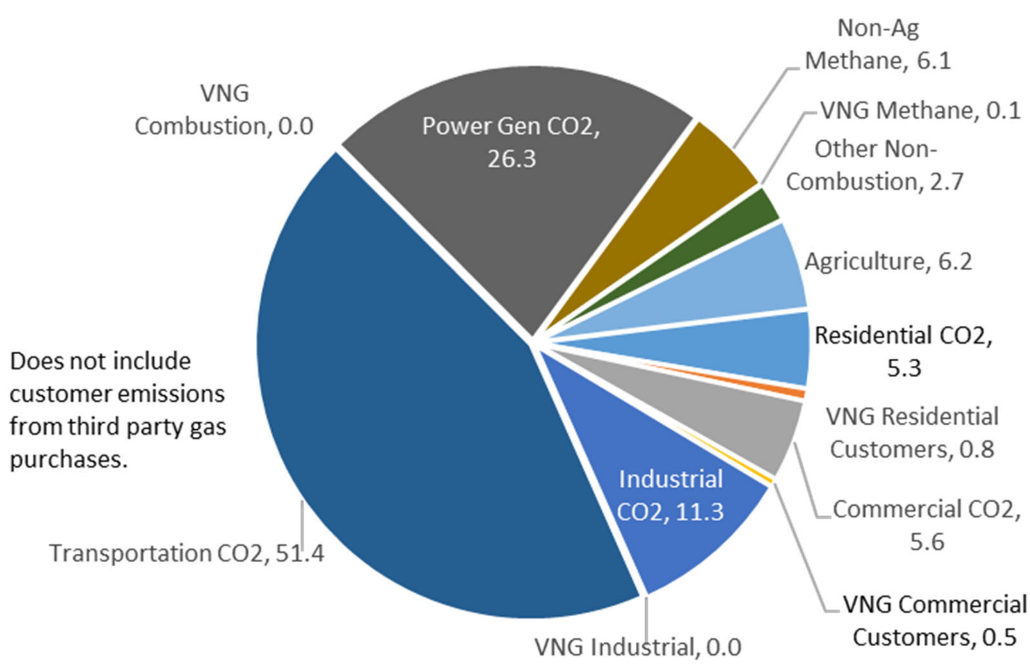
- The U.S. Energy Information Administration (EIA) provides data on fossil fuel consumption by state that can be used to calculate the associated CO_2 emissions.
- The U.S. EPA Greenhouse Gas Reporting Program (GHGRP) reports GHG emissions including non-combustion GHG emissions from large industrial 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 emissions from that sector for this analysis.

Table 3 summarizes this estimate of Virginia GHG emissions.

Table 3 - Estimated Virginia GHG Emissions – 2019 (MMt CO_2e)

Source	MMt CO_2e	Data Source
Combustion		
Residential	6.2	EIA
Commercial	6.1	EIA
Industrial	11.4	EIA
Transportation	51.4	EIA
Power Gen	26.3	EIA
Combustion Subtotal	101.4	
Non-Combustion		
Methane - Landfills	2.9	GHGRP
Methane - Coal Mines	2.7	GHGRP
Methane - Gas Systems	0.3	GHGRP
Methane - Other	0.1	GHGRP
Other Non-CO_2	0.3	GHGRP
Non-Combustion CO_2	2.4	GHGRP
Manure Management	2.6	EPA SIT
Enteric Fermentation	0.8	EPA SIT
Soil Management	2.7	EPA SIT
Other Ag	0.2	EPA SIT
Non-Combustion Subtotal	15.0	
Total	116.4	

Figure 5 - Estimated Virginia and VNG GHG Emissions - 2019 (MMt CO_2e)



Comparing these results (in million tonnes) with the VNG data in Table 2 (1000 tonnes) and Figure 5, VNG's direct emissions in 2019 had the following characteristics:

- VNG’s total direct GHG emissions were less than 0.1% of the estimated total Virginia GHG emissions.
- VNG’s methane emissions were less than 1% of estimated total Virginia methane emissions.
- The total VNG direct and indirect emissions including gas owned and sold by VNG were 1.3% of the estimated total Virginia GHG emissions.

The remainder of this report discusses ways that VNG 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, VNG use of electricity, and upstream emissions from production, processing, and transportation of gas. Section 6 discusses mitigation of GHG sources outside of VNG’s 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.

3 Renewable Natural Gas

3.1 Overview

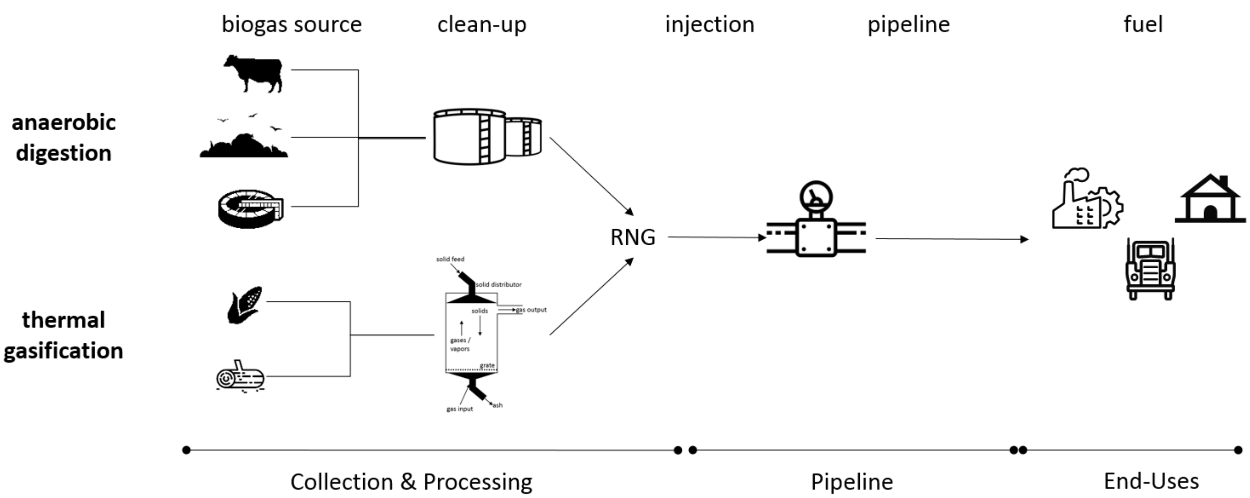
RNG is derived from biomass or other renewable resources and is pipeline-quality gas that is fully interchangeable with conventional natural gas. As a point of reference, the American Gas Association (AGA) uses the following definition for RNG:[10]

> *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.* [11]

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.[12]

RNG is produced over a series of steps (see Figure 6): 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 6 - 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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[10] AGA, 2019. RNG: Opportunity for Innovation at Natural Gas Utilities, https://pubs.naruc.org/pub/73453B6B-A25A-6AC4-BDFC-C709B202C819

[11] 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.

[12] 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.[13] 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

[13] "Air quality–related health damages of food", Nina G. G. Domingo, et al, SQDV P d| 4;/ 5354 44; +53,h534696:44;> kwwsv=22grl1ruj243143:62sqdv1534696:44;

- 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[14] concluded that after “two decades” of experience in biomass gasification, “‘tars’ can be considered the Achilles heel of biomass gasification.”

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[14] 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.[15] Sierra Energy's thermal gasification and biorefinery facility in Nevada produces RNG and liquid fuels using municipal solid waste as a feedstock.[16] 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.[17] Further afield there are demonstration and early-commercialization thermal gasification projects across Europe, including Sweden, France and Austria.[18] 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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[15] 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.
[16] Sierra Energy, 2020. https://sierraenergy.com/projects/fort-hunter-liggett/
[17] West Biofuels, 2020. http://www.westbiofuels.com/projects?filter=research
[18] 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.

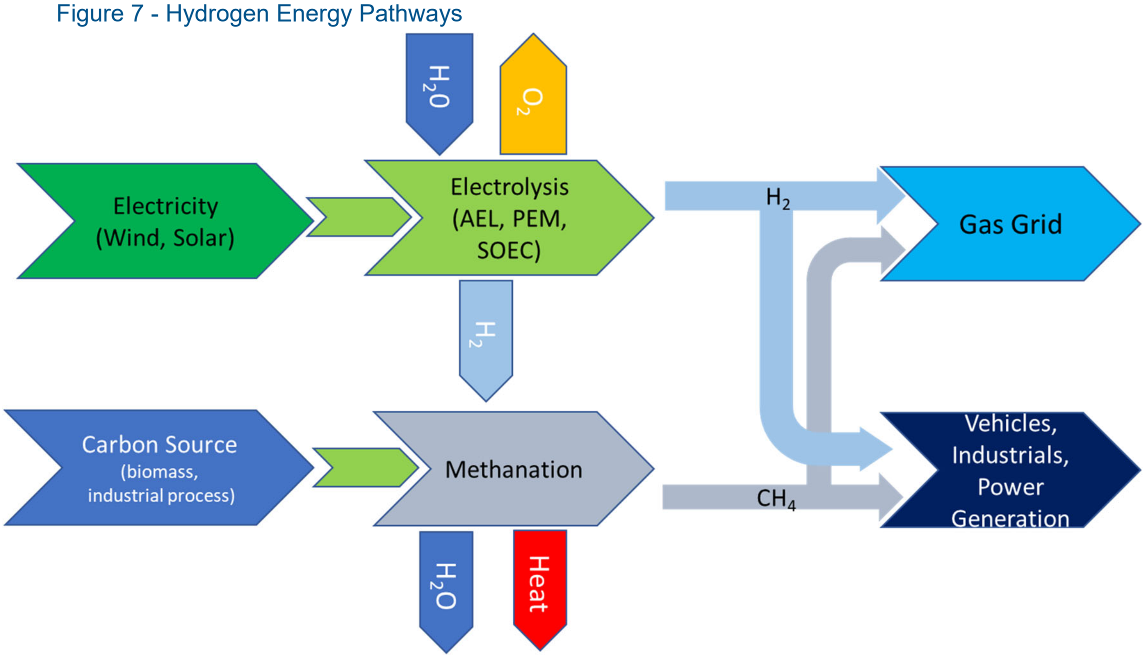
electrolysis technologies with different efficiencies and in different stages of development and implementation:

- 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 7 - 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[19] and some locations in the U.S. (for example Hawaii Gas[20])

[19] "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
[20] https://www.hawaiigas.com/clean-energy/hydrogen/

and is a potential future resource for VNG.

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 VNG

ICF has developed an RNG inventory and projection for the VNG service territory and the Commonwealth of Virginia. 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 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

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.

The estimates included in Table 6 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 VNG's deliveries of conventional gas. The VNG portion is relatively small due to the company's small geographical footprint but there is a robust supply in

Virginia overall that could be tapped. Agriculture is Virginia's largest private industry[21] and the benefits of RNG production in creating value for agricultural produces and in reducing waste could be significant.

Table 6 - Technical Potential for RNG Production by Feedstock in VNG Service Territory (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

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 23% 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

[21] http://www.vdacs.virginia.gov/markets-and-finance-agriculture-facts-and-figures.shtml

scenario ranges from 40% to 50% at medium biomass prices. The Moderate Deployment scenario captures 40% of the potential RNG feedstock resource available.

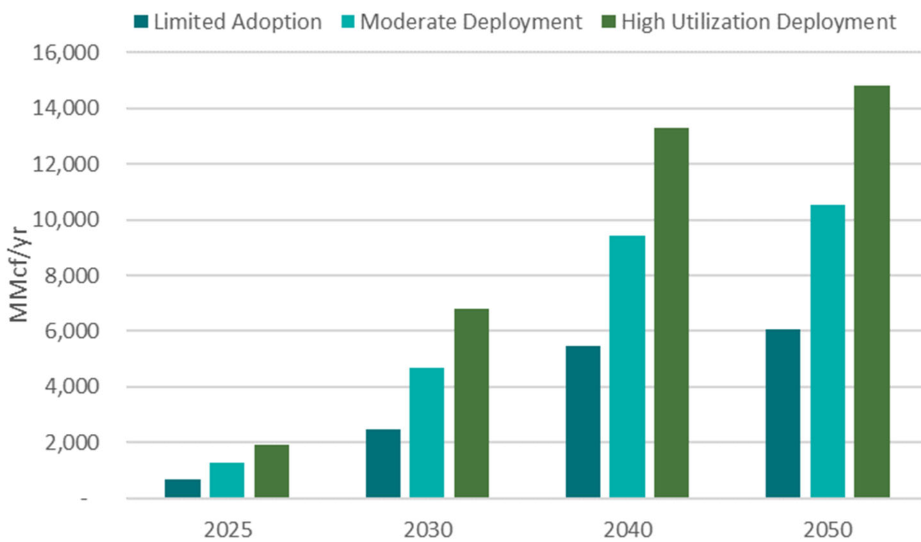
- **High Utilization Deployment** represents higher levels of utilization, with a range from 50% to 90% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rate of feedstocks for thermal gasification in this scenario ranges from 50% to 70% at medium-to-high biomass prices. The High Utilization Deployment scenario captures 56% 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 6,000 MMcf in the Limited Adoption scenario to almost 15,000 MMcf in the High Utilization Deployment scenario in the VNG service territory 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 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 8 - Growth Scenarios for Annual RNG Production in VNG Service Territory (MMcf/yr)

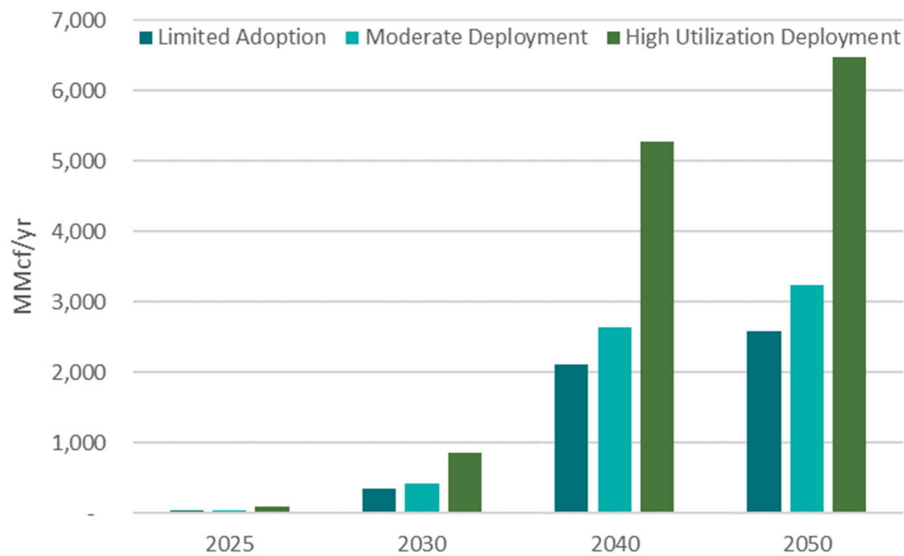


ICF's estimates for P2G augment the biomass-based RNG supply by an additional 2,600 to 6,500 MMcf across the three scenarios in 2050. The primary determinant of P2G supply is the availability of renewable electricity for electrolysis, ranging from curtailed renewable generation only to generation that 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.

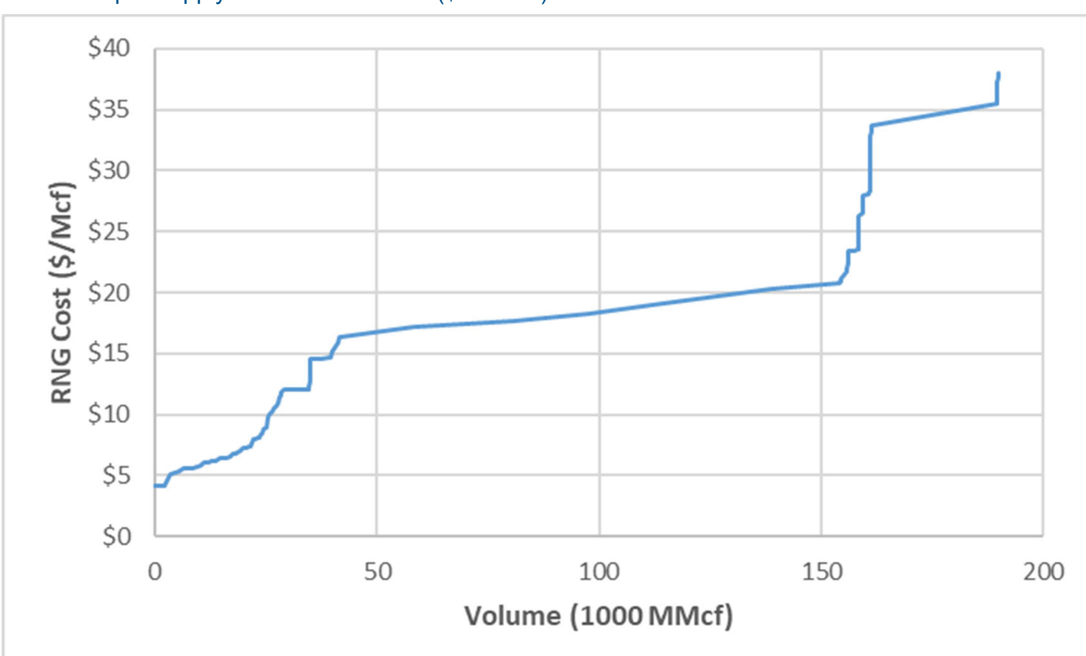
Figure 9 - P2G Production Scenarios for VNG (MMcf/y)



3.4 Supply-Cost Curve for RNG

The figure below 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.

Figure 10 – Example Supply-Cost Curve - 2050 ($/MMBtu)



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.

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 VNG service territory would be from dairy and swine operations, however others may exist. Depending on the characteristics of the facilities and the discounts applied, there could be from 2,000 to 3,000 Mt CO_2e of offsets produced from these sources in the VNG service territory by 2050. A larger potential for such offsets exists in Virginia outside the VNG service territory.

3.6 Comparison to VNG Deliveries

Figure 11 and Figure 12 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 gas deliveries are categorized as:

- Owned Customer Gas – the utility sells the gas directly to customers
- Commercial Transportation Gas – the utility transports the gas for marketers and other sellers of gas to commercial customers
- Other Transportation Gas – the utility transports the gas for marketers and other sellers of gas to industrial and power generation customers,

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. VNG has a limited RNG supply due to its relatively small, urban service territory but still has the potential to meet the future demand for owned and sold gas and commercial transportation gas. That said, 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. The ICF projections also estimate a robust supply of RNG in Virginia outside of the VNG service territory.

Figure 11 – RNG Potential vs VNG Gas Deliveries by Supply Case (MMcf/yr)

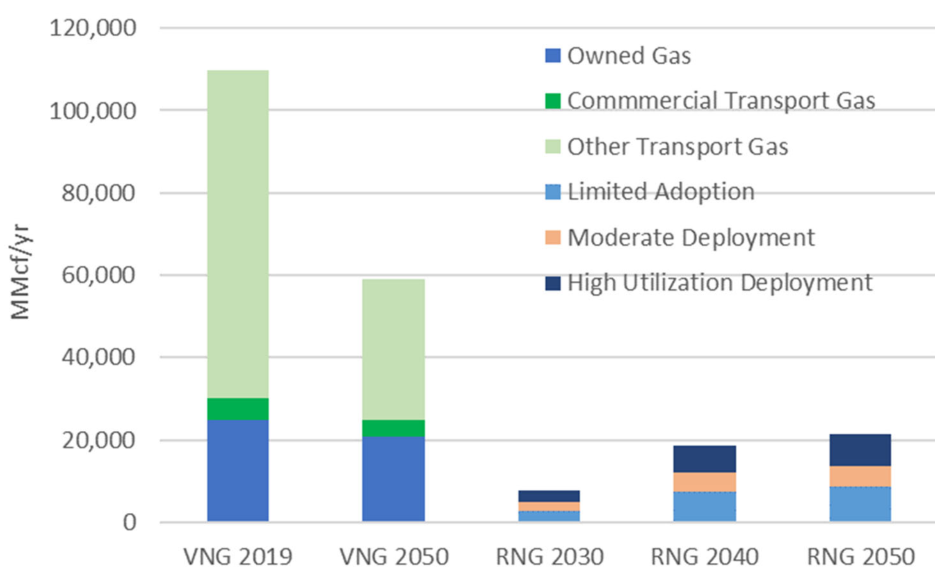
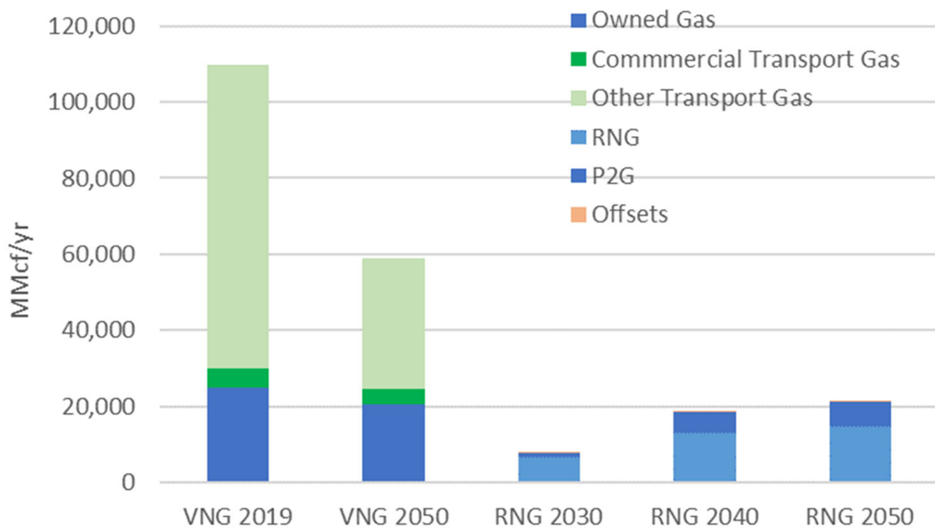


Figure 12 shows the breakout of the RNG, P2G, and offset equivalent gas volume in the High Utilization Deployment case.

Figure 12 – RNG Potential vs VNG Gas Deliveries by Supply Type (MMcf/yr)



3.7 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:

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

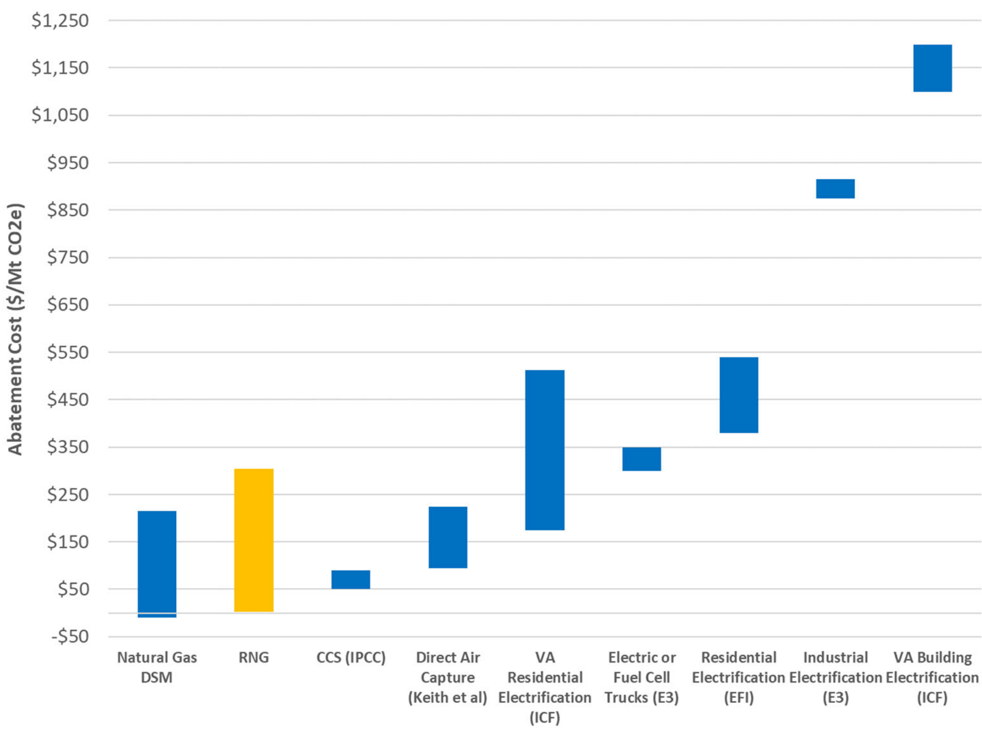
where the RNG_{cost} is the cost from the estimates reported previously. The fossil natural gas price is the range of Virginia citygate prices reported by the EIA for years 2015 to 2019,[22] ranging from \$3.89/MMBtu to \$4.87/MMBtu. The front end of the supply-cost curve is showing RNG of less than \$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 is \$304/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 13 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),[23] RNG (from this study), carbon capture and storage (CCS),[24] direct air capture (whereby CO_2 is captured directly from the air and a concentrated stream is sequestered or used for beneficial purposes),[25] battery

[22] EIA, Natural Gas Data, https://www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_PG1_DMcf_a.htm
[23] 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).
[24] 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.).
[25] 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

electric trucks (including fuel cell drivetrains),[26] and policy-driven electrification of certain end uses (including buildings and in the industrial sectors).[27,28] The building electrification value is the average across all building types. The range for residential buildings is $175 to $513/tonne CO_2e. The range for commercial and institutional buildings is $1,332 to $5,317/tonne CO_2e due to the higher cost and lower efficiency of some equipment configurations. 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.

Figure 13 - GHG Abatement Costs, Selected Measures ($/Mt CO_2e)



[26] E3, 2018. Deep Decarbonization in a High Renewables Future, https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization
[27] Energy Futures Initiative (EFI), 2019. Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California, https://energyfuturesinitiative.org/efi-reports.
[28] ICF- Scenario 3 in this report.

4 Mitigation of Direct Emissions

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

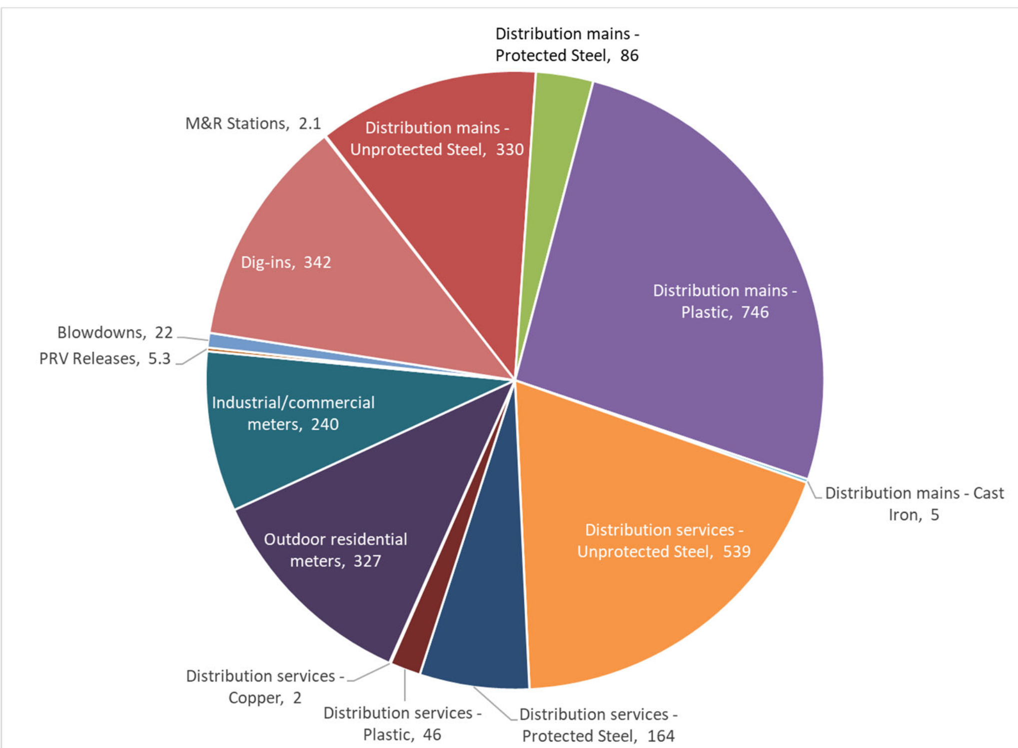
- Methane emissions (fugitive and vented) from LDC operations.
- CO_2 emissions from combustion at the LDC and fleet operations.

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.

Figure 14 shows the breakdown of the methane emissions, which totaled 2,856 metric tonnes of methane (Mt CH_4) in 2019 or 71.4 1000 Mt CO_2e when weighted by the GWP.

Figure 14 - VNG Methane Emissions 2019 (Mt CH_4)



These emission estimates are based on U.S. EPA emission calculation methodologies from the National Inventory of Greenhouse Gas Emissions and Sinks[29] (GHGI) and the EPA Greenhouse

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

Gas Reporting Rule (GHGRP).[30] 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 14 shows that three components accounted for 99% of the emissions. Customer meters comprised 20%, distribution mains and services comprised 67%, and dig-ins (damage to mains and services from construction) comprised 12%. The potential pathways to reduce these emissions include:

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

4.1.1 Customer Meters

The 2019 EPA emissions estimates for meters are 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.[31] 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 emissions estimate by 349 Mt, or a 12% increase in total 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 account 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.

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

[30] Greenhouse Gas Reporting Program, https://www.epa.gov/ghgreporting
[31] 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

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, or reduced from 566 to 113 Mt CO_2e.

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.

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 most of the higher emitting pipe materials in the VNG system have already been replaced, there were still some unprotected steel services and mains and a small amount of cast iron mains. VNG 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 45% — even as the system grew by approximately 30%. It is assumed that the remainder of the high-emitting pipe will be replaced under pipeline integrity and safety programs, resulting in 842 Mt CH_4 per year of emission reductions once the replacements are complete, from 1,917 to 1,076 Mt CO_2e. While these replacements are currently being paid for under pipeline integrity programs, Table 8 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 8 - 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 potentially more accurate company-specific emission factors for mains and services has 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 was 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 from VNG would result in a reduction of over 50% from the EPA estimate, from 342 to 146 Mt CH_4. The actual estimate would be based on the future calculations and could also be the basis for improved damage reduction programs. VNG 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 EFVs) and programs to prevent and minimize third party damages.

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, 0.1% and 0.8% 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[32] 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 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 Summary of Methane Reductions

Table 9 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 9 - 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

4.1.6 Methane Capture Offsets

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

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

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 certification 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 in the VNG service territory 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). Due to VNG's relatively small, urban service territory, the potential for offsets inside the service territory is limited, potentially 2 to 3 1000 Mt CO_2e of methane offsets from dairy and swine operations in 2050. This is less than the remaining methane emissions of 33.7 1000 Mt CO_2e (1,347 Mt CH_4). This would require acquisition of methane offsets from outside the VNG service territory, where there is a robust potential for offset development.

4.2 CO_2 from Combustion – Fleet Emissions

Beyond methane emissions, there are CO_2 emissions. VNG maintains a fleet 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 10 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.[33] 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 at VNG. 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. VNG is already using CNG vehicles and operates the required fuel infrastructure. GHG-

[33] https://greet.es.anl.gov/

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.

Table 10 – 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 VNG'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 VNG's 2019 direct emissions. Residential and small commercial customers comprised 99% of VNG's sales volumes and 23% of total deliveries. With appropriate regulatory approval and support, VNG is uniquely positioned to assist with decarbonization of 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.

VNG's existing Energy Efficiency Program already offers customers rebates on high-efficiency equipment, a free online energy audit with a downloadable report and free energy-savings kits. 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 11 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.[34] 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.

The measures are installed gradually through requirements for new construction and stock turnover in existing buildings as shown in Table 12. The implementation of gas heat pumps is more gradual due to the newness of the technology.

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[34] 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 13 provides more detail on the equipment and cost assumptions for these scenarios.

Table 11 – 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 12 - 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 13 - 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%

Table 14 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.[35] 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

35 https://www.eia.gov/outlooks/aeo/

able to reduce customer CO_2 emissions by 79% in 2050. In Scenario 2, efficiency plus RNG results 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 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 14 - Summary of 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 ($2020 Millions)		7,125	9,408
NPV of GHG Emission Reductions (MMt CO_2)		22	25
Emission Reduction Costs ($/t$CO_2$)		$ 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 presented in the above Scenario Summary. Figure 15 shows the overall reduction in VNG residential and commercial natural gas demand out to 2050.

Figure 15 – Annual Gas Demand (Trillion Btu)

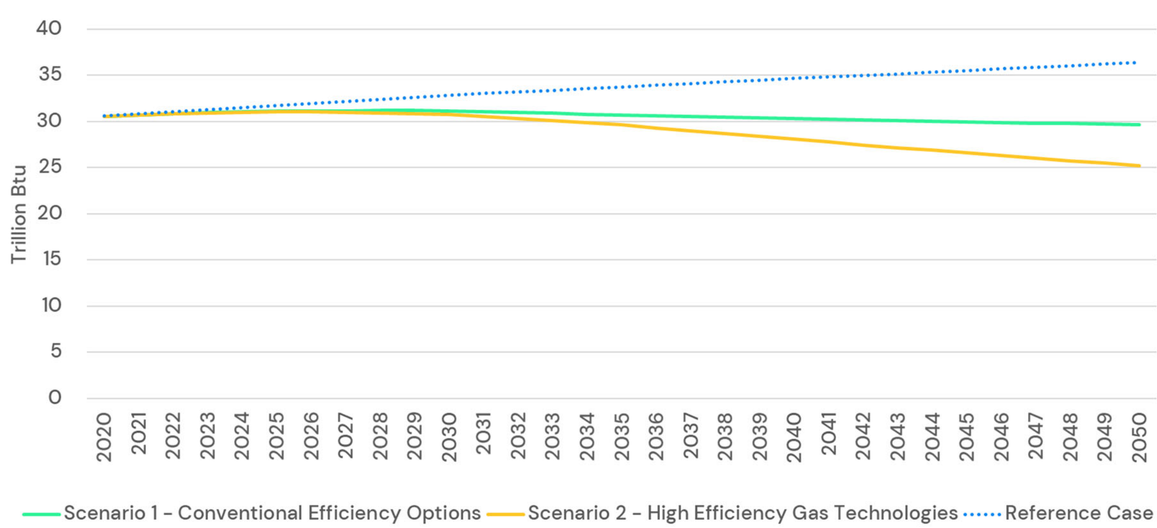


Figure 16 shows the total increase in energy costs from the gas scenarios, including the incremental upfront costs to install higher efficiency equipment and better insulate homes, changes in the energy costs to customers (based on reference case natural gas rates and the reduction in natural gas consumption), and incremental costs to purchase decarbonized gases (RNG and P2G). Figure 17 provides additional context on the make-up of those changes in customer energy costs.

Figure 16 – Total Annual Costs - Equipment Installations and Incremental Energy Costs) ($Millions)

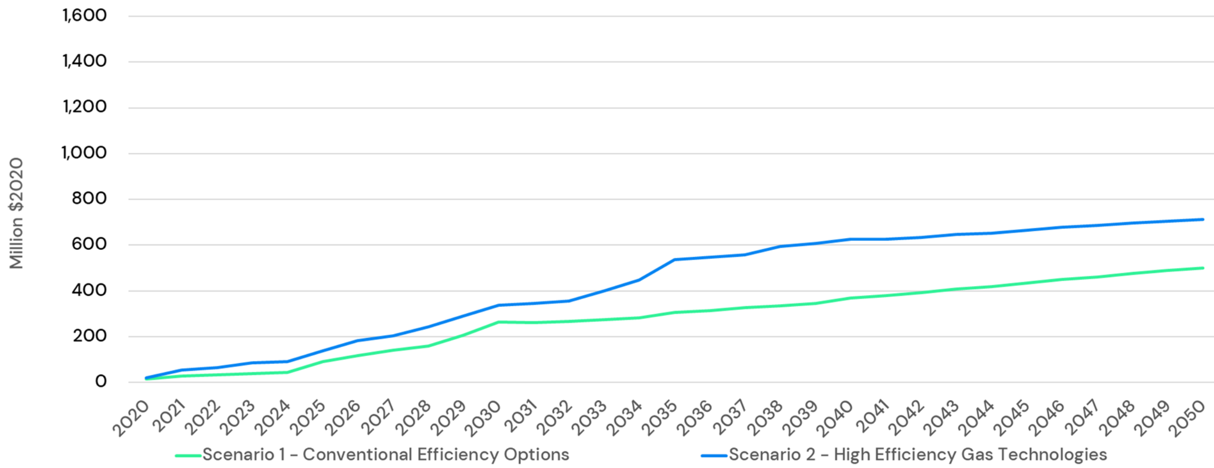


Figure 17 – Incremental Annual Energy Costs ($Millions)

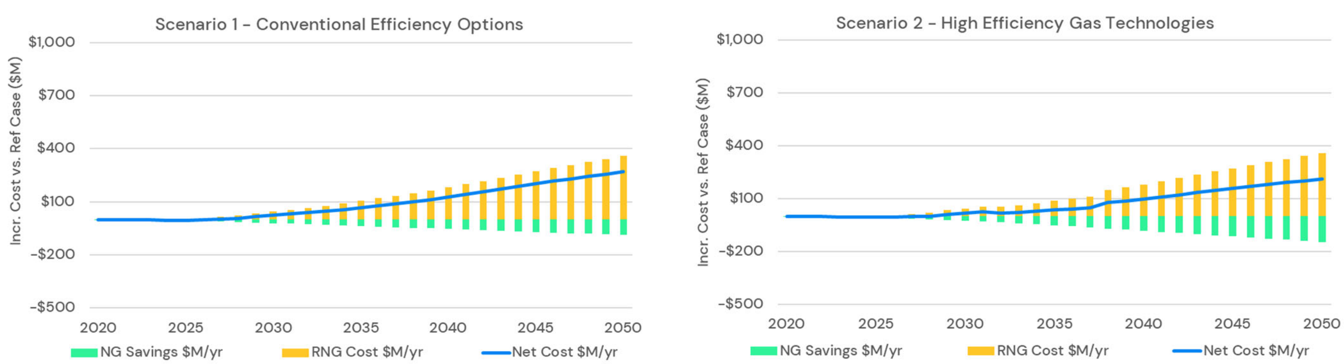
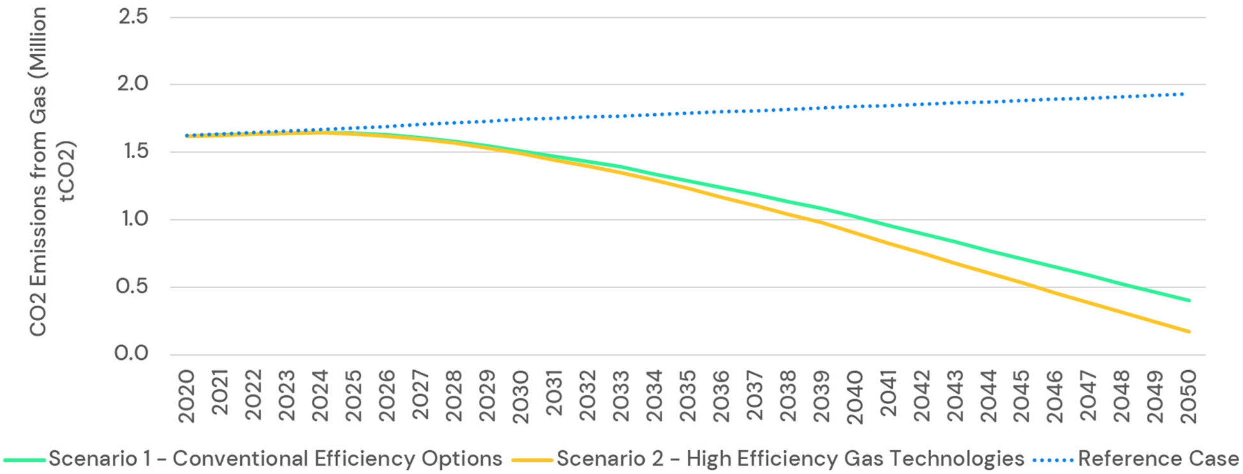


Figure 18 shows the emission reduction pathways for both of these scenarios. If RNG was not included in these scenarios, and no other changes were made, the GHG emission reductions would be reduced, matching gas demand reductions from Figure 15, but the emission reductions costs ($/t$CO_2$) would also be lower.

Figure 18 – CO_2 Emissions from Natural Gas (Million tCO_2)



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 emission 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 15 compares current Virginia gas and electricity prices and average emissions on a consistent per MMBtu basis. 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 15 - Comparison of Virginia Natural Gas Electricity Cost and Emissions[36]

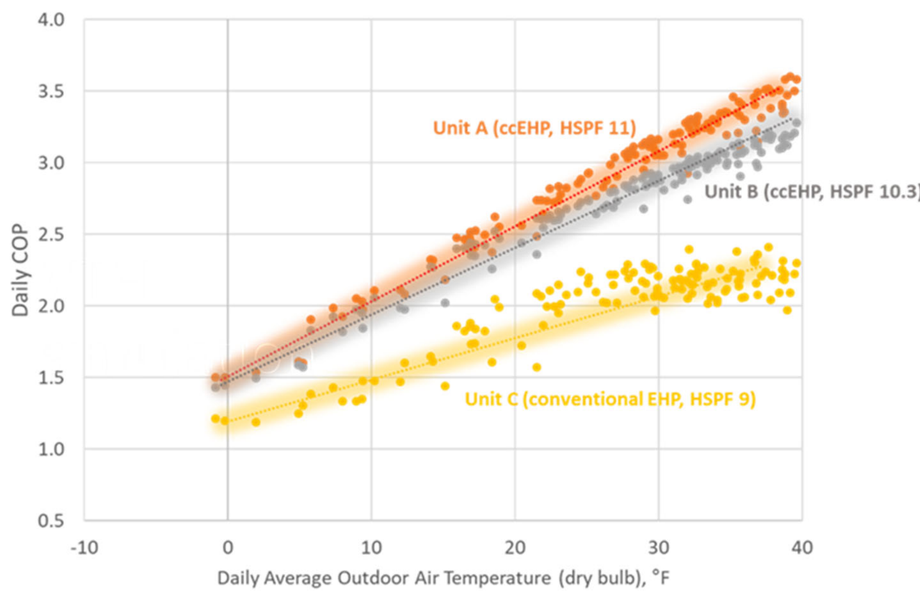
	Gas		Electricity			
	$/MMBtu	kg CO_2 /MMBtu	$/kWh	$/MMBtu	kg CO_2 /MWh	kg CO_2 /MMBtu
Residential	$12.62	53	$0.10	$27.89	309	90.5
Commercial	$8.53	53	$0.08	$23.97	309	90.5
Industrial	$4.66	53	$0.07	$20.10	309	90.5

[36] 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

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, increasingly relying on back-up resistance heat (COP=1) as temperatures drop below zero, as shown in Figure 19.

Figure 19 - 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 16 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.

Table 16 – Electric Scenarios for Customer Modeling

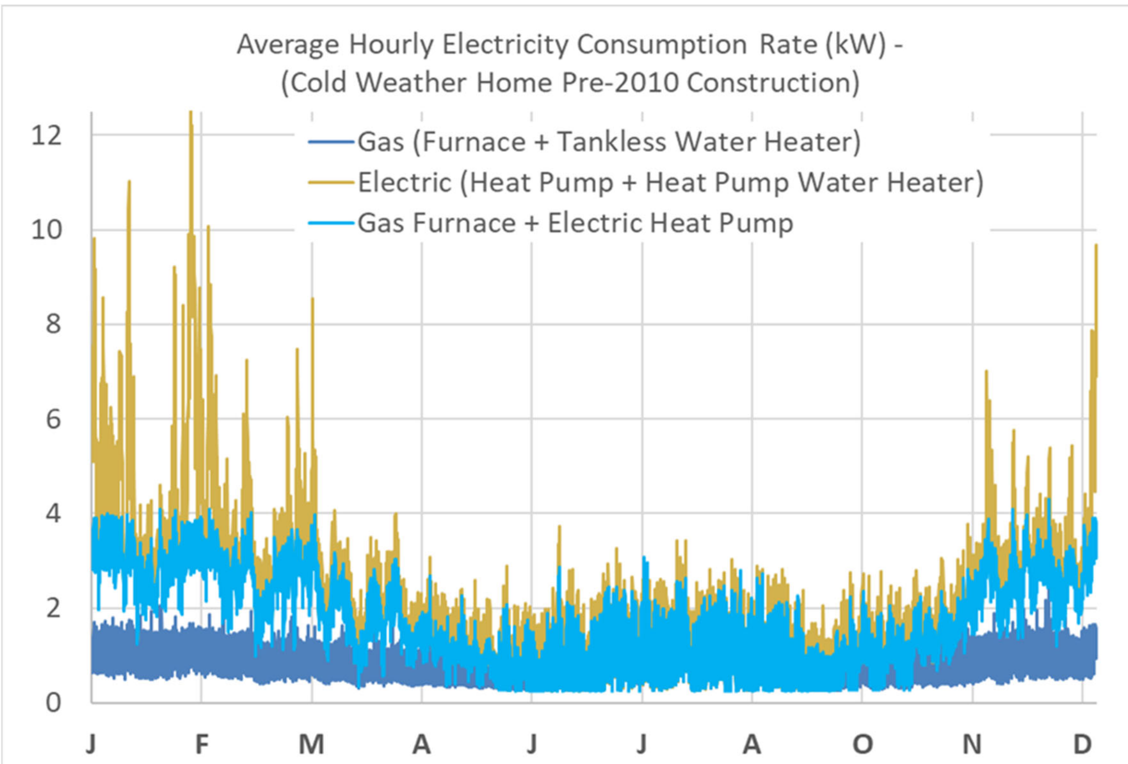
	Scenario 3	Scenario 4
Sub-Sector Groupings	**Policy-Driven Mandatory Electrification**	**Gas/Electric Hybrid Approach**
Single family Multifamily Small commercial	New Construction - Net-zero Ready Homes (~80% reduction)	New Construction - Net-zero Ready Homes (~80% reduction)
	Existing Building Retrofits – 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

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. VNG 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.

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 20 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 20 - Gas/Electric Hybrid Systems Can Reduce Electric Demand Peaks



Source: Gas Technology Institute

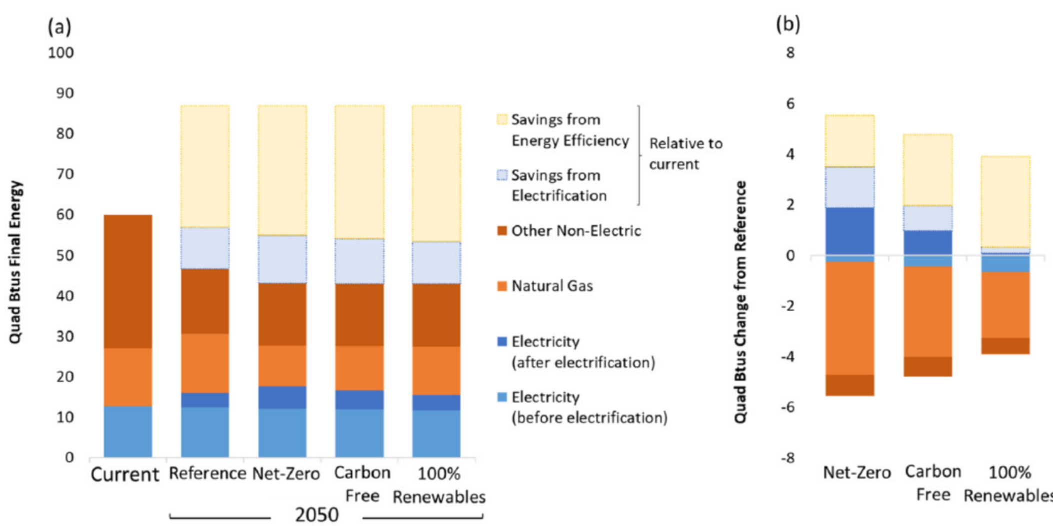
Providing increased electric supply is complicated in this case by the need to be decarbonizing the grid at the same time. Decarbonization may require retirement of fossil fuel generators or implementation of other solutions like carbon capture and storage, which would need to be addressed along with 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 potentially for vehicle electrification. Finally, the scenario implies the replacement of almost 220,000 customer heating systems over 30 years or over 7,000 units per year on average.

The costs of electric system decarbonization combined with the additional costs to support mandatory end use electrification would 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.[37] 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 21) 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 21 - EPRI Decarbonization Analysis Results[37]



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 in Virginia for 2019 and adjusting them out to

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

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).

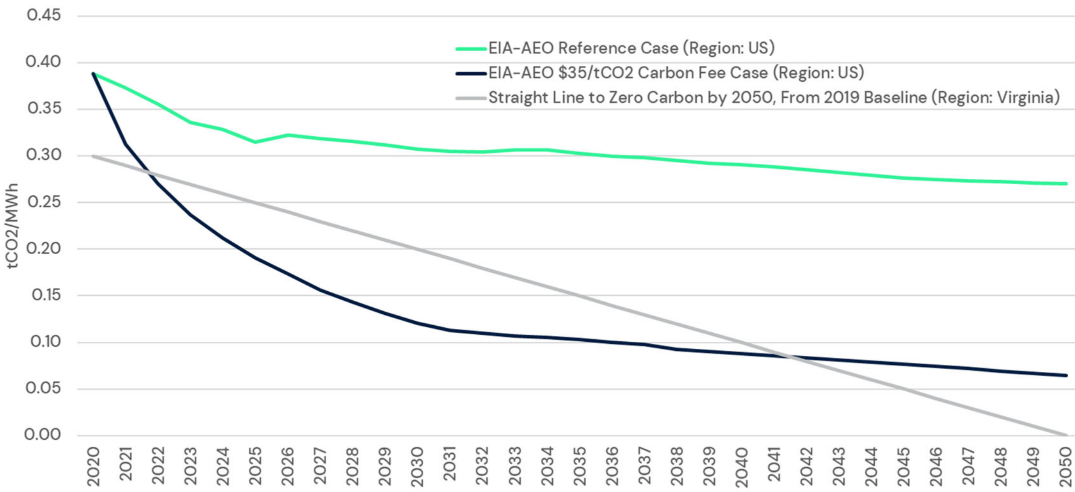
ICF in collaboration with the client developed a range of potential electricity price impacts based on the EPRI analysis and the implications of further electrification in addition to the scenarios considered in the EPRI analysis. ICF then allocated values from that range to the different scenarios in this study. ICF added these 'incremental cost elements' to the reference case (declining) electric rates as shown in Table 17. 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 17 – 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
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 in Virginia, shown as the gray line in Figure 22.

Figure 22 - Grid Decarbonization Trajectories



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 18 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 18 - 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

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. Table 19 summarizes the equipment cost and performance assumptions for these scenarios.

Table 19 - 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%	

Table 20 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 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 20 - 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)	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 17),

- 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 17, 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 CO2 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 23 shows the overall reduction in VNG residential and commercial natural gas demand out to 2050.

Figure 23 – Annual Gas Demand (Trillion Btu)

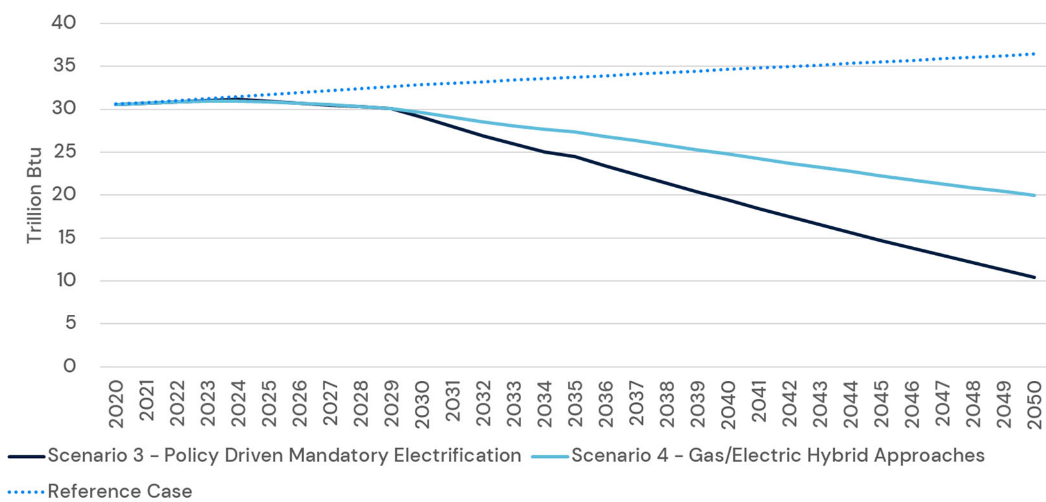


Figure 24 shows the total increase in energy costs from the electrification scenarios, including the incremental upfront costs to install higher efficiency equipment, electric equipment, or better insulate homes, and changes in the energy costs to customers.

Figure 24 – Total Annual Costs - Equipment Installations and Incremental Energy Costs ($Millions)

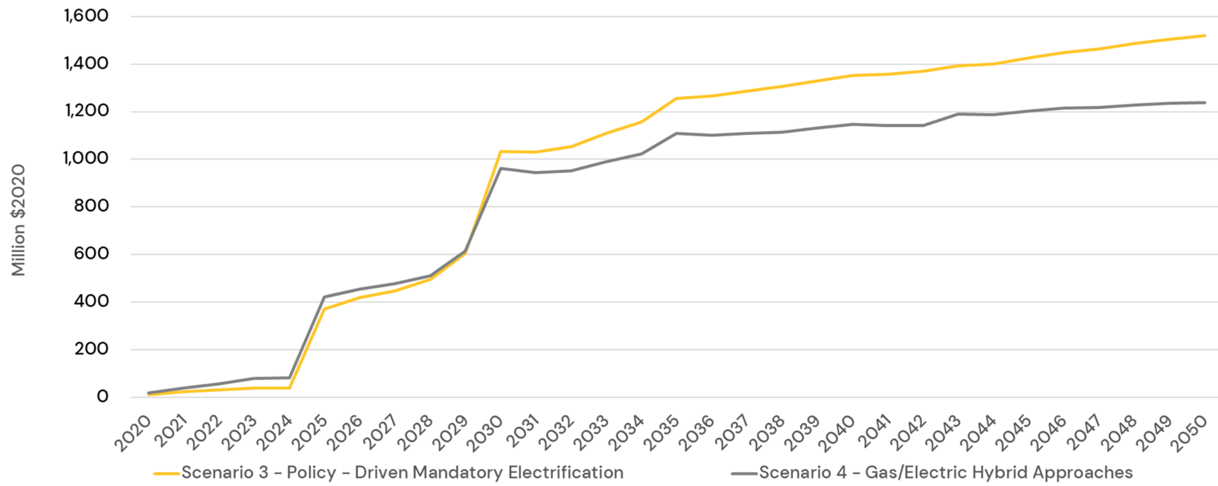


Figure 25 provides additional detail on the make-up of the changes in customer energy costs discussed above.

Figure 25 – Incremental Annual Energy Costs ($Millions)

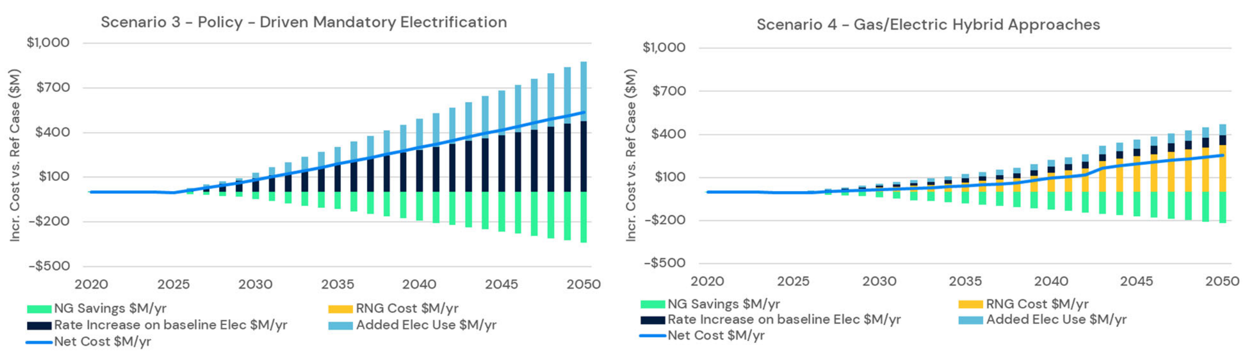
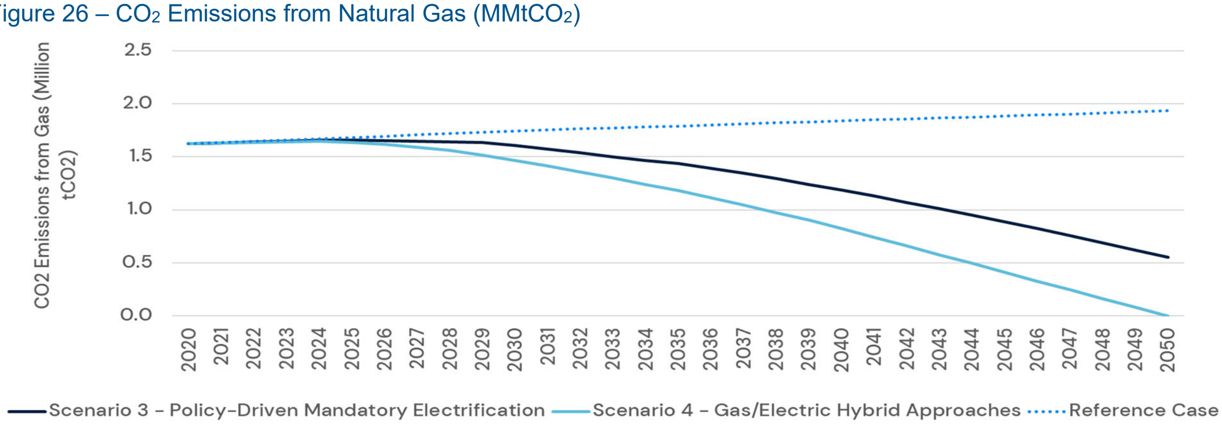


Figure 26 shows the emission reduction pathways for both of these scenarios. The use of RNG in the Gas/Electric Hybrid Scenario results in larger emission reductions by 2050 than the Policy-Driven Mandatory Electrification Scenario analyzed here.

Figure 26 – CO_2 Emissions from Natural Gas (MMtCO_2)



5.1.3 Results of Customer Modeling

Table 21 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 21 - 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)	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 27 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 as the High Efficiency Gas Technology scenario.

Figure 27 - Scenario Cost and Reduction Comparison

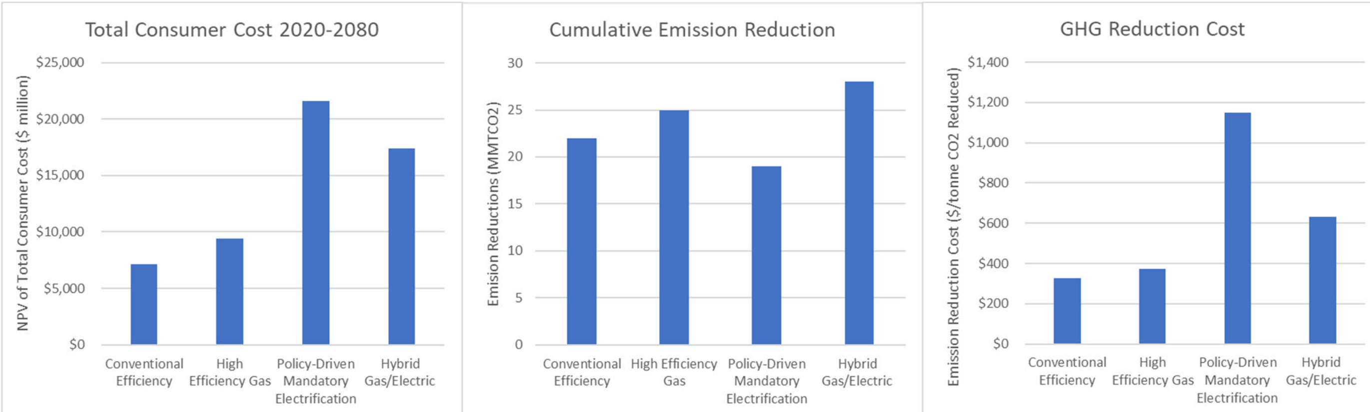


Table 22 shows the emission reduction cost by the various customer segments for new and existing building types. The gas technologies typically have the lowest cost due primarily to the deep reductions achieved through high efficiency and CO_2-neutral RNG. For Scenarios 2, 3, and 4, higher emission reduction 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 22 - 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

5.2 Large Industrial Customers

As noted earlier, 97% of VNG's industrial gas deliveries in 2019 were to only 59 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 some 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 three times more expensive than gas on a Btu basis (see Table 15), 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 three-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. The VNG gas deliveries to large industrial customers are estimated to be the equivalent of 500 MW of base load electric capacity,[38] which would be the equivalent of a new gas combined cycle plant and associated delivery assets. At $1000/kW[39] of capacity, this would be $500 million for new gas combined cycle 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.

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 VNG 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.[40] 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).[41] CHP is a widely applied technology

[38] 12,513,381 Mcf of industrial transportation consumption = 3,666,388 MWh of energy. At 80% capacity factor = 0.5 GW of demand.
[39] https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf
[40] https://www.southerncompany.com/newsroom/2021/feb-2021/hydrogen-r-and-d-effort-to-achieve-net-zero-goals.html
[41] https://www.epa.gov/chp

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

5.3 Electricity Use for VNG Business Operations

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

- End use energy efficiency: VNG 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: VNG can also purchase electricity from renewable energy generators and/or purchase renewable energy credits to effectively eliminate upstream emissions from its electricity supply.

These emissions will decline over time to the extent that the electric grid decarbonizes including as required by the VCEA,.

5.4 Reduction of Upstream Emissions from Gas Supply

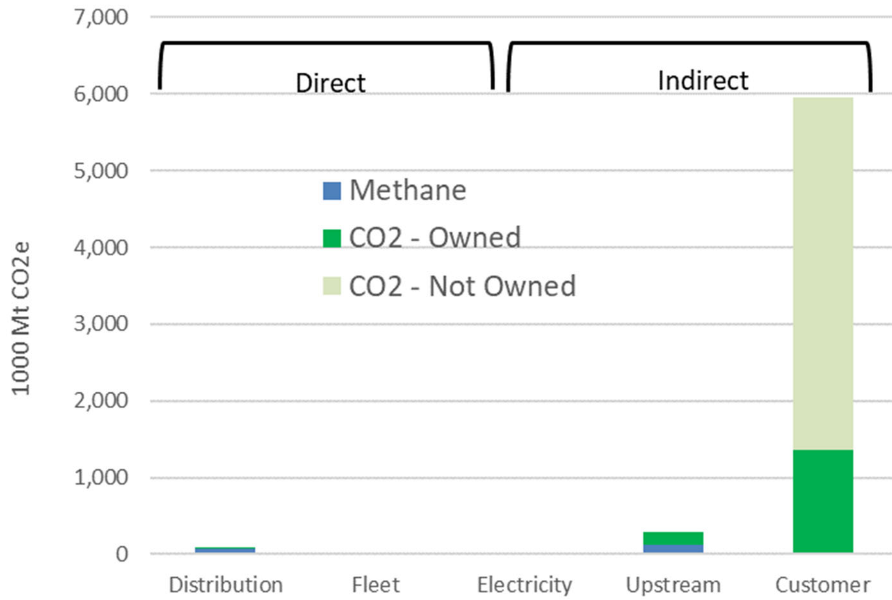
In addition to the emissions from customer use of gas, VNG's indirect emissions include the emissions from the production, gathering, processing, and delivery of natural gas. The emissions include:

- 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[42] 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 to VNG, roughly split evenly between methane and CO_2. (This compares to 54.4 kg CO_2/Mcf from combustion of the gas itself.) Figure 28 shows the direct and indirect emissions including upstream emissions from gas owned and sold by VNG. This does not include the transportation gas that is purchased from other sources by customers and only delivered by VNG because VNG does not know and cannot control the source of that gas.

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

Figure 28 – VNG Direct and Indirect Emissions - 2019 (1000 Mt CO_2e)



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 VNG can reduce the emissions from gas transportation via pipelines.

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. VNG's parent organization, Southern Company 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, VNG 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 VNG's Operational Scope

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

6.1 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. VNG could 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.

6.2 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 VNG develops RNG resources, it will capture methane and avoid direct emissions from those other sectors of the state economy. As an example, the potential for reductions from dairy and swine operations under the High Utilization Deployment supply scenario would be equivalent to 2,000 to 3,000 Mt CO_2e per year.

6.3 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 VNG Decarbonization Pathway

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.

7.1 Direct Emissions

Figure 29 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. 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 29 - Methane Emissions Reduction Pathway – (1000 Mt CO_2e)

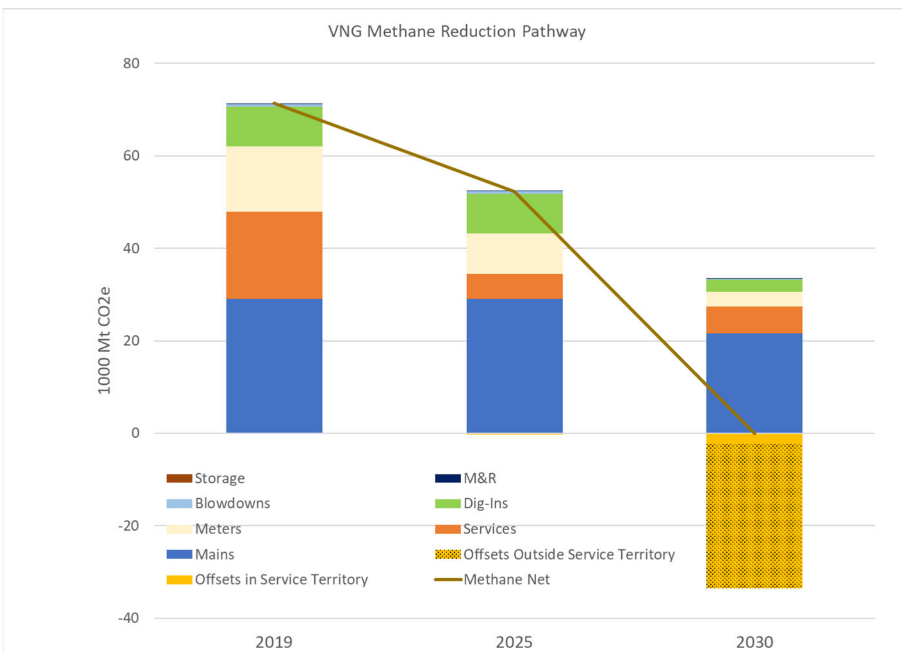


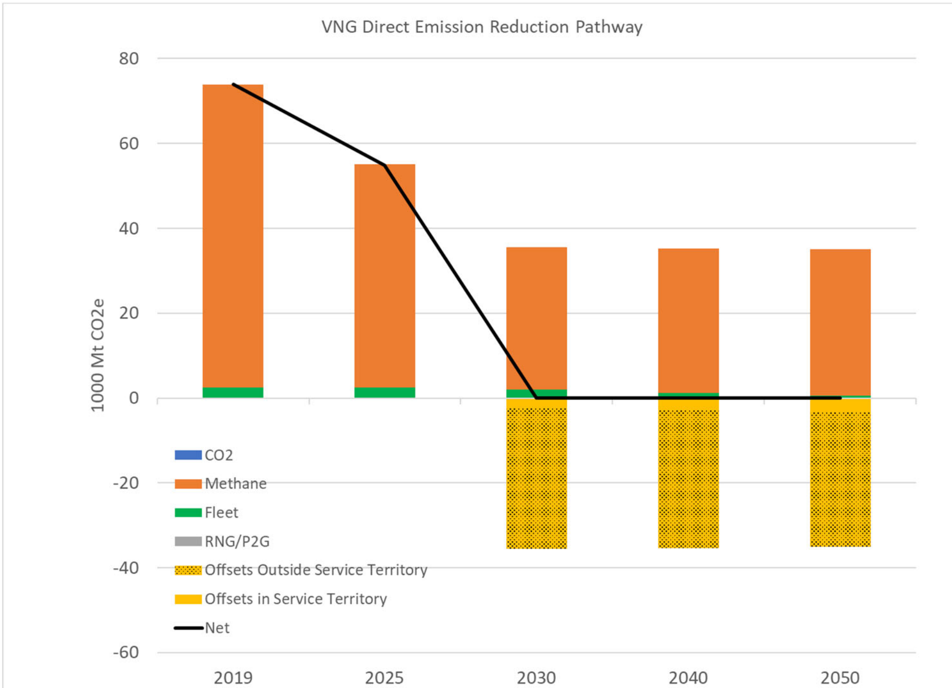
Figure 30 shows the reduction pathway for direct emissions. There are many options for decarbonization of the vehicle fleet, including RNG, hydrogen, electrification, and other alternative fuels. In this case it is assumed that some combination of these measures causes fleet emissions to decline from 2019 levels by:

- 20% in 2030

- 50% in 2040
- 80% in 2050.

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 30 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 30 - VNG Direct Emissions Reduction Pathway (1000 Mt CO_2e)



7.2 Indirect Emissions

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.

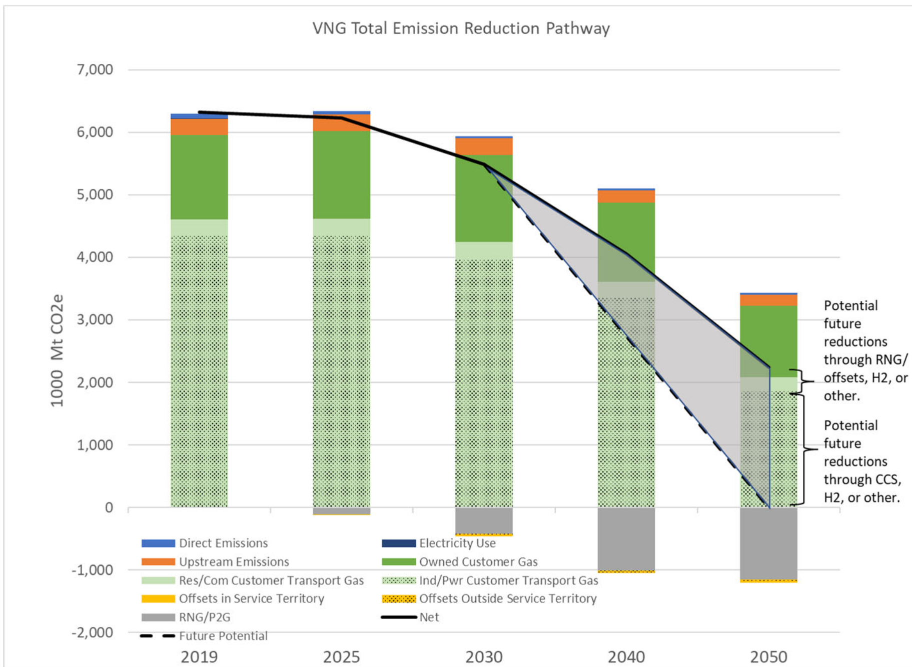
As discussed earlier and shown in Figure 31, emissions from the customer use of gas are by far the largest source of direct or indirect emissions. As noted above, this pathway analysis includes emissions from all of VNG's customers' use of gas, which is beyond VNG's Scope 3 emissions under applicable GHG protocols, which only include gas owned and sold by VNG. The following additional assumptions were made to develop the total reduction pathway:

- 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 VNG. Methane intensity is assumed to be 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.

- Residential/commercial customers – Separately modeled to project reductions. See Scenario 2 in Section 5.
- 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 the power sector including the VCEA.

Figure 31 - VNG Total Emission Reduction Pathway (1000 Mt CO_2e)



With these assumptions, 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 was projected to be net zero 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 from combustion of transportation gas delivered to VNG customers could potentially be reduced or offset through use of hydrogen, RNG, combined heat and power, offsets from other sources, or use of carbon capture and sequestration.

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 VNG 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 VNG decarbonization pathways include all three of these options. As a regulated utility, VNG's ability to implement them depends on approval and support from policymakers, the Virginia State Corporation Commission (SCC), 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 VNG 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

The analysis presented in this report projects that there is a feasible gas-based pathway to support GHG emissions reductions in the Commonwealth of Virginia at a lower cost than other decarbonization pathways modeled or reviewed for this study. It also supports the following conclusions:

Natural Gas Plays a Key Role in the Southeastern Virginia Energy Economy

VNG is the natural gas local distribution company in the southeastern Virginia, Hampton Roads region, serving over 300,000 customers including 12 critical national defense facilities and major employers in the region. VNG's natural gas infrastructure is a highly reliable and resilient system that delivers energy at half to one fifth the cost of electricity.

VNG Can Play a Key Role in Decarbonizing the Virginia Economy

The gas-based GHG reduction pathways identified in this analysis were projected to achieve net zero GHG emissions from operations by 2050 and broader sustainability goals according to the desired timeline. These pathways would preserve or enhance system safety, reliability, and resilience goals and could 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 are 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 this existing system and the end use gas equipment owned by consumers could be a faster, less expensive pathway to reducing Virginia GHG emissions than a policy-driven mandatory electrification approach that requires major restructuring and rebuilding of energy supply infrastructure and broader replacement of customer equipment.

VNG's Direct Emissions are a Very Small Part of the Virginia Inventory

VNG's direct GHG emissions include the following:

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

The direct emissions totaled 74 thousand Mt CO_2e in 2019. The largest component was methane emissions from the distribution operations. That said, 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%. The CO_2 emissions from vehicle fleets is a much smaller component. VNG's total direct GHG emissions were less than 0.1% of the estimated total Virginia GHG emissions in 2019. The direct methane emissions were less than 1% of the estimated Virginia methane emissions.

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

- Emissions from power plants that supply electricity used by VNG.

- Upstream emissions from the production, processing, and transportation of gas that is owned and sold by VNG.
- Emissions from customer use of gas delivered by VNG.

Emissions related to customer gas use are several orders of magnitude larger than any of the other sources, almost 6 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.[43] Roughly 20% of the customer emissions are from gas owned and sold by VNG versus gas purchased from other sources by customers and delivered by VNG. The total direct and indirect VNG emissions including gas owned and sold by VNG were 1.3% of the estimated total Virginia GHG emissions 2019. The upstream emissions cited in this report include only gas owned and sold by VNG because VNG does not control and cannot track the emissions from gas provided by other entities.

Renewable Natural Gas Can Provide Environmental and Economic Benefits to VNG's 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.

In addition to providing a CO_2-neutral fuel at the point of use, 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 from that waste directly into the environment as a GHG. It also displaces fossil-based natural gas uses including thermal use, electricity generation, and use as a transportation fuel. RNG development also creates construction and operation jobs and secondary economic benefits.

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[43] 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 it its reporting program. On the other hand, according to the current WRI/WBCSD GHG Protocol, VNG's Scope 3 emissions would be limited to the gas owned and sold by VNG, 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 VNG and identify opportunities to reduce those emissions, but also noted that there are more limited actual Scope 3 emissions.

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, 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.

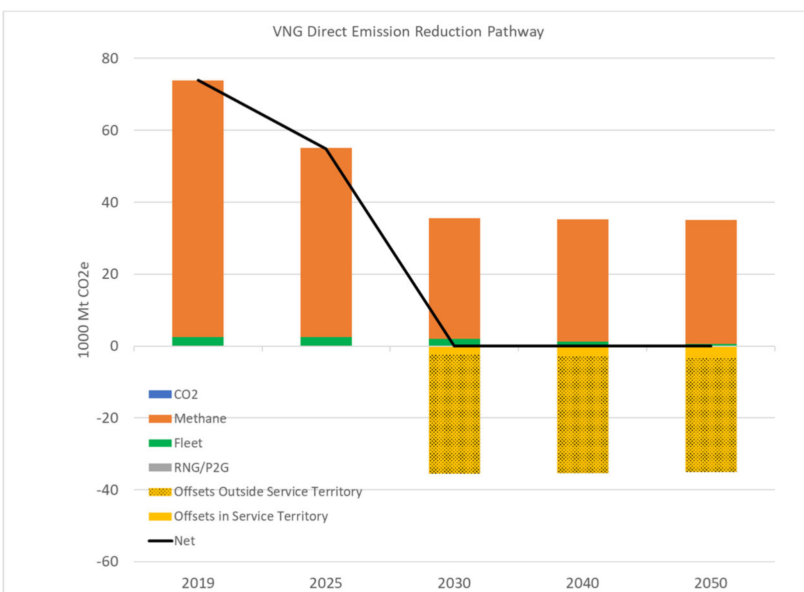
Another renewable gas option is the use of hydrogen produced through electrolysis with renewable-sourced electricity. The hydrogen produced in this way is a highly flexible energy product that can be:

- 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 (known as Power to Gas or P2G).

Southern Company is actively engaged in the research and development of new approaches for the production and use of hydrogen as a GHG-neutral fuel

There is a Pathway for VNG 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 VNG's 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 analysis shows the potential for a 53% reduction in methane emissions between 2019 and 2030. The remaining methane emissions could be mitigated through the use of methane capture offsets from RNG projects.The figure below shows the pathway for mitigation of direct emissions through direct reductions of methane emissions, fleet emissions, and the use of methane offsets and RNG to fuel storage compressors. It achieves net zero methane emissions by 2030 and net zero for all direct emissions by 2050.



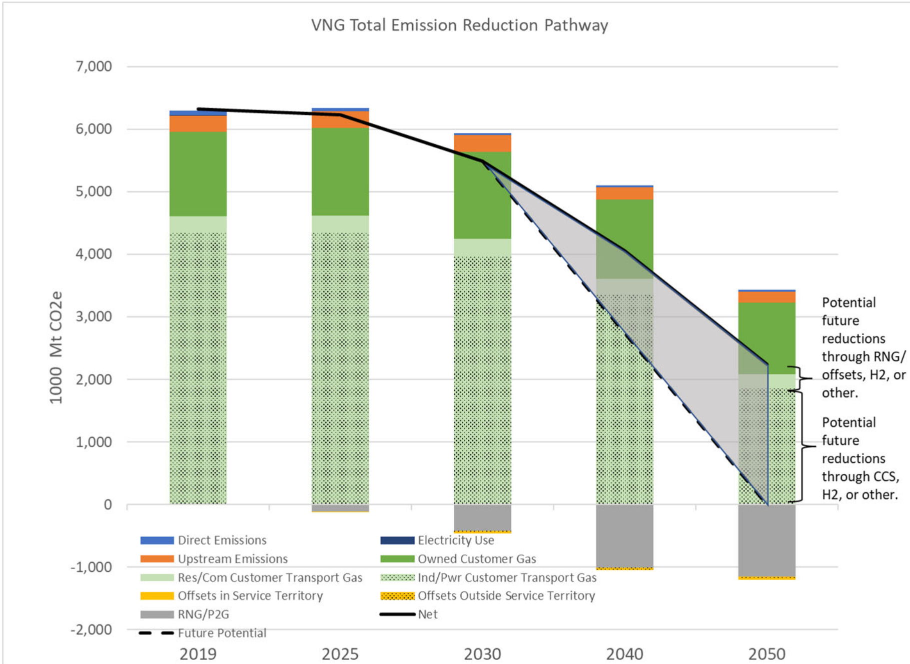
There is a Pathway for VNG to Reduce or Offset its Indirect GHG Emissions

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 - Implementation begins in 2030. Almost 80% of customers install high efficiency gas furnaces or boilers by 2050 with RNG. 35% of 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 and reach 54% of single family homes, 28% of multi-family, and 38% of commercial buildings by 2050. 30% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic insulation. RNG replaces natural gas by 2050.
- Scenario 3 – Policy-Driven Mandatory Electrification - All-electric equipment required for new construction as of 2025. Conversion to electric space and water heating required for replacements starting in 2030. All-electric share reaches 93% in single family homes and 87% in commercial buildings by 2050. 30% of buildings get deep energy retrofits by 2050, and 16% 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. By 2050, hybrid heating reaches 75% of single family homes and 75% of commercial buildings. 30% of buildings get deep energy retrofits by 2050, and 16% get air sealing/ attic. 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 but also may have implications for the natural gas system.

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 results for the residential and commercial sectors. 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. With these assumptions, 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 was projected to be net zero 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 are primarily from large industrial and power generation customers who purchase their own gas supply. VNG could work with these customers to reduce their emissions through the use of hydrogen, RNG, combined heat and power, or offsets from other sources or use of carbon capture and sequestration.

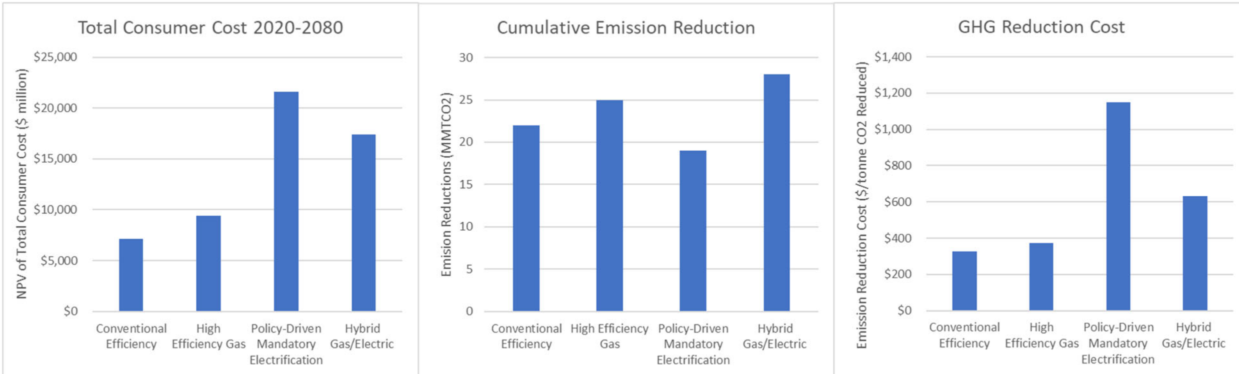
The Natural Gas Pathways Offer Additional Consumer Benefits

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 More Cost-Effective Than The Mandatory Electrification Scenario Modeled

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 less than \$400/tonne CO_2e, roughly one third that of the policy-driven, mandatory electrification scenario modeled here.

Summary of Scenario Results



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 Virginia and its citizens is likely to change over time and should be able to adapt to future regulatory structures, market developments, consumer needs, and technology developments.