

The Role of Gas Networks in a Low-Carbon Future



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About this Paper

This paper was prepared by M.J. Bradley & Associates (MJB&A), an ERM Group Company, on behalf of the Downstream Natural Gas Initiative (DSI). It outlines key strategies for natural gas utilities to decarbonize their infrastructure and operations, as well as to support the transition to a decarbonized economy in their service areas, all in line with their core objectives of providing a safe, reliable, affordable, and sustainable energy supply.

The paper was prepared by MJB&A based on research and engagement with DSI members on the DSI Long-Term Vision, which is currently under development. It reflects the analysis and judgment of the MJB&A authors alone.

Brian Jones, Sophia Hill, Jane Culkin, and Pye Russell of MJB&A made important contributions to this paper. Jim Howe of Bay Utility Associates, LLC served as an Advisor.

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About M.J. Bradley & Associates

M.J. Bradley & Associates, an ERM Group company, is a multi-disciplinary team of experts with a long-track record of advising industry, NGOs, and government agencies on energy and environmental policy, technology, and implementation. Our staff have backgrounds in law, engineering, finance, policy, and environmental science. At the beginning of March 2020, MJB&A was acquired by ERM and became part of the ERM Group of companies.

About the Downstream Natural Gas Initiative

The Downstream Natural Gas Initiative (DSI) is a group of leading natural gas utilities collaborating to build a shared vision for the role of utilities and the gas distribution network in the transition to a low-carbon future. DSI is facilitated and managed by MJB&A. DSI is focused on opportunities to leverage the existing infrastructure to support near- and long-term environmental and economic goals and to address key technical and regulatory challenges related to these goals and opportunities.

Through this collaboration, DSI is advancing a Long-Term Vision and related strategies for natural gas utilities to reduce greenhouse gas emissions and enable the transition to carbon neutrality.

Members of DSI include Consolidated Edison of New York, DTE Energy, Enbridge Gas, Eversource, Liberty Utilities, National Grid, NiSource, NW Natural, Philadelphia Gas Works, Pacific Gas & Electric, Southern California Gas, and Vermont Gas.

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Executive Summary

The 2020s will be a decisive decade for curbing the effects of climate change. According to the Intergovernmental Panel on Climate Change (IPCC), in order to avoid the worst impacts of climate change, the world must roughly halve global greenhouse gas (GHG) emissions by 2030 and achieve net-zero GHG emissions by mid-century.¹ To meet this significant task, states and provinces across the U.S. and Canada have established ambitious targets to reduce economy-wide GHG emissions. Achieving carbon neutrality will require deep decarbonization across the entire North American economy and all forms of energy, including natural gas.

Today, natural gas currently supplies a reliable and affordable source of energy to major sectors of the economy. However, to achieve mid-century GHG emission reduction goals, deep decarbonization studies and pathway analyses conclude that economy-wide fossil fuel consumption must drastically decline over the next several decades. This poses considerable challenges for natural gas utilities (also referred to as local distribution utilities, or LDCs), whose regulated business models center around procuring reliable and affordable supplies of natural gas and delivering them safely over the gas networks to end-users.

At the same time, the low-carbon energy transition also provides a unique opportunity for LDCs to decarbonize their operations and to provide services that align with a carbon-neutral future. While increased supply of renewable electricity and electrification of end uses will play a key role in decarbonizing the economy, gaseous forms of energy that can be stored over long periods of time, as well as the underlying natural gas infrastructure, can play a critical complementary role in delivering renewable and low-carbon fuels reliably and cost-effectively.

For example, gas networks provide significant energy storage capacity and add a layer of resilience when compared with a decarbonization approach that relies exclusively on electricity. Gas and the gas networks also play an essential role in meeting peak energy demand for not only gas, but also electricity. These services can provide complementary value to an electric sector that is projected to grow with the electrification of other sectors (such as transportation and buildings). A number of recent studies, largely in Europe and the United Kingdom, have shown that developing complementary roles for the gas and electric sector in a low-carbon future can help to maximize energy reliability and minimize the overall costs of economy-wide decarbonization.²

By repurposing the gas networks to transport low-carbon fuels—including renewable natural gas (RNG), hydrogen, and synthetic natural gas—this infrastructure, as well as the workforce to maintain it reliably and safely, can play a long-term role in enabling a carbon-neutral economy.

This paper outlines key strategies for LDCs to decarbonize their infrastructure and operations, as well as to support the transition to a decarbonized economy in their service areas, all while enabling them to continue to provide a safe, reliable, affordable, and sustainable energy supply. This includes strategies to:

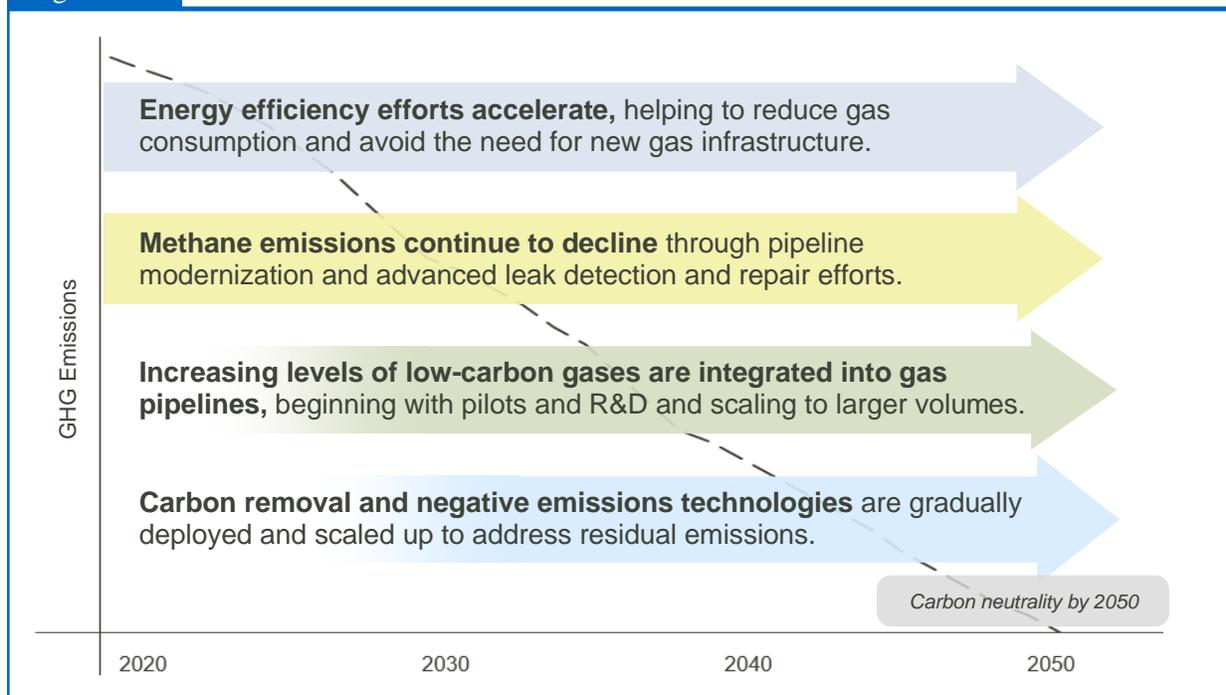
- **help customers become more energy efficient** through building retrofits, advanced efficient technologies, and other emerging innovative technologies such as district heating, to reduce gas demand as well as total energy demand across the economy;
- **drastically reduce and eliminate methane emissions from their networks and operations** as well as throughout the full natural gas supply chain; and
- **supply customers with lower and zero-carbon sources of energy** by gradually repurposing the gas networks to supply increasing amounts of renewable energy, including RNG, hydrogen, and synthetic natural gas.

While it is possible to substantially reduce GHG emissions using technologies and strategies that are commercially available today, transitioning to a carbon-neutral economy will be a significant undertaking, ultimately requiring innovations in technologies that are currently either not commercially available at scale or cost-competitive without government incentives. Achieving this transition will require changes in

regulatory and business models, as well as new collaborations and partnerships between policymakers, academia, customers, and utilities. Achieving carbon neutrality will also require additional strategies to remove carbon from the atmosphere, including carbon capture, utilization, and sequestration (CCUS), forestry and agriculture sequestration, and carbon offsets.

By addressing these challenges head-on and taking action to decarbonize their networks, LDCs can better respond to customer preferences, take advantage of the opportunity to explore non-traditional capital investments and innovative business models, maintain a thriving workforce, and contribute to the transition to a low-carbon future.

Figure 1 Illustrative Transition to Decarbonized Gas Networks



Vision Statement of the Downstream Natural Gas Initiative

This paper was prepared on behalf of the Downstream Natural Gas Initiative (DSI), a group of leading natural gas utilities collaborating to build a shared vision for the role of utilities and the gas distribution network in the transition to a low-carbon future.

DSI has adopted the following vision statement:

“The natural gas network has a central role to play in realizing a viable carbon-neutral economy. In support of this carbon-neutral future, natural gas utilities are taking actions to decarbonize natural gas services, repurpose existing gas networks to both store and deliver increasing amounts of renewable energy, help customers better optimize their energy use, and support carbon negative technologies. With advances in technology and supportive policy frameworks, gas networks will enable carbon emissions reductions and climate action today and into the future.

Natural gas utilities are working together and with other key stakeholders to deliver on this vision.”

DSI's Long-Term Vision and the Current Status of the Decarbonization Dialogue

To achieve mid-century GHG emission reduction goals, deep decarbonization studies and pathway analyses conclude that economy-wide fossil fuel consumption must drastically decline over the next several decades. What remains less clear is what is the most achievable and cost-effective path—or combination of decarbonization strategies—to achieve these goals.

In collaboration with DSI, MJB&A is undertaking an assessment of the electric and natural gas system costs of different decarbonization scenarios, with a focus on the role of gas networks. The objective of this analytical effort is to evaluate scenarios that leverage “sector coupling” – the complementary pairing of the electric and gas networks to achieve carbon neutrality together rather than relying exclusively on the electricity network. A variety of decarbonization pathways analyses have been published across North America that show a range of results for the costs and benefits of electrification as well as other decarbonization options for natural gas systems. While most illustrate the need to significantly reduce fossil fuel consumption (including natural gas) across all economic sectors to achieve deep decarbonization, this type of analysis is an evolving field with limitations of current work.

MJB&A recently conducted a review of North American decarbonization studies to assess how these studies depict the role of natural gas and gas networks in a low-carbon future, as well as to understand how different assumptions and analytical approaches may influence study findings. MJB&A identified several gaps in its review. For example, several of the studies did not consider how future cost declines for certain emerging technologies, such as hydrogen from renewable electricity (green hydrogen), might influence study outcomes. Other studies relied on near-total building electrification without sufficiently considering the technical, policy, and consumer adoption barriers to implementing this strategy, as well as its full economic costs. Certain studies also failed to adequately account for unique regional factors, such as climate zone, electric grid constraints, and peak system demand, when developing assumptions and decarbonization strategies. These gaps help identify opportunities to improve future decarbonization assessments and suggest that it is beneficial to conduct such assessments at the local and regional level.

At the same time, in recent years, several decarbonization analyses in Europe and elsewhere have shown that sector coupling can help to maximize energy reliability and minimize the overall costs of decarbonization. The path to carbon neutrality, as well as the exact roles of the electric and gas networks, will differ among jurisdictions. However, there currently exists a gap in research regarding the potential of the gas networks to contribute to cost-effective decarbonization in North America.

In recognition of these gaps, MJB&A's analytical assessment will evaluate the electric and natural gas system costs of achieving a carbon-neutral economy. This will include an assessment of electric and natural gas utility costs of a greater role for energy efficiency, increased supply of renewable energy resources, and integration of the electric and gas networks over the longer term to achieve decarbonization goals. In developing this analytical assessment, MJB&A is conducting original research and analysis, facilitating discussions among DSI members, and soliciting input from a multi-stakeholder Advisory Group.

The Role of Natural Gas

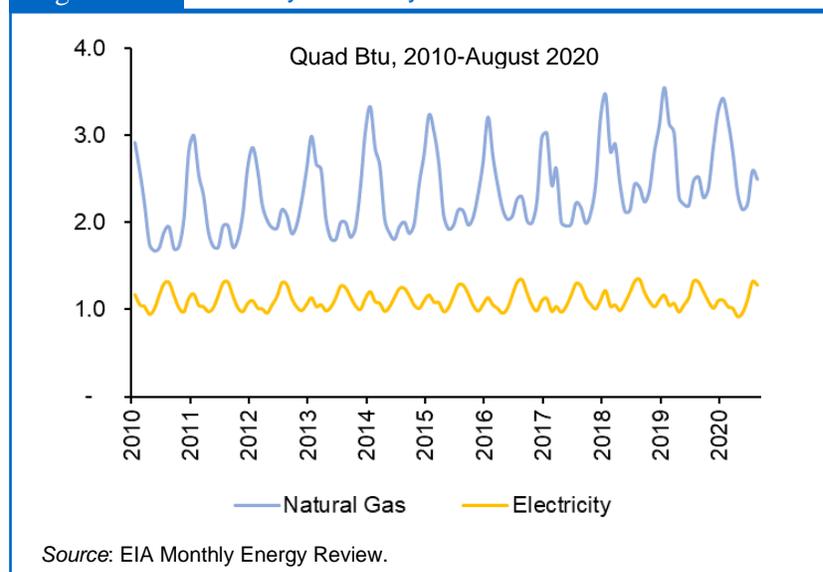
Natural Gas Today

Natural gas plays a critical role in North America’s current energy mix, supplying roughly one third of total primary energy demand.¹ The bulk of this energy is transported through the natural gas transmission and distribution networks and is used by nearly every major sector of the economy, including buildings, industrial processes, power generation, and transportation:

- **Buildings:** In residential and commercial buildings, natural gas is used for space and water heating, cooking, and clothes drying, among other end uses. Natural gas plays a particularly important role in space heating and is the main heating fuel choice for residential homes in most regions. Forty-seven percent of U.S. households rely on natural gas as their main source of heating, compared with 36 percent who rely on electricity.³
- **Industry:** Major natural gas consumers in the industrial sector include manufacturing (where natural gas helps to fulfill high-temperature process heat requirements) and the chemical industry (where natural gas is used as a feedstock to produce methanol and ammonia).⁴
- **Power generation:** In the U.S., natural gas-fired turbines generated roughly 37 percent of electricity generation in 2019, more than any other form of power generation.⁵ The reliable firm power provided by gas-fired generation is particularly valuable in places like California that have increasing levels of intermittent renewable generation.
- **Transportation:** Two forms of natural gas—compressed natural gas and liquified natural gas (or CNG and LNG)—are currently used in heavy-duty trucks, freight rail, and marine shipping, although they represent a small share of both transportation fuel demand and total natural gas consumption.⁶ When used as a vehicle fuel, natural gas can offer life cycle GHG emissions benefits over conventional fuels, depending on vehicle type, duty cycle, and engine calibration.⁷

Gas infrastructure delivers a significantly higher amount of energy to end-consumers than electricity grids. These differences are heightened when considering peak system demand: in the U.S., the natural gas system delivers roughly three times more energy on the coldest day of the year than the electric grid does on the hottest (see Figure 2). Even assuming major efficiency gains from switching from gas to electricity, replacing this amount of energy delivery with electricity would be extremely challenging. Gas grids also provide a major source of energy storage and flexibility.

Figure 2 Monthly Electricity and Natural Gas Use in the U.S.



At the same time, there are GHG emissions associated with the natural gas supply chain: methane and carbon dioxide (CO₂). Methane, which has a higher global warming potential (GWP) than CO₂, is released during the production, transmission, and distribution of natural gas. CO₂ and nitrous oxide (NO_x) are emitted when natural gas is burned in equipment or appliances, such as furnaces and water heaters.

¹ In the U.S., natural gas supplied roughly 32 percent of primary energy consumption in 2019. In Canada, it supplied 35 percent as of 2016.

The natural gas sector is the second largest anthropogenic source category of methane emissions, contributing 22 percent of U.S. methane emissions in 2018. Of these emissions, natural gas distribution systems are responsible for a small portion (roughly seven percent).⁸

The use of natural gas across the economy is responsible for roughly one third of U.S. carbon emissions.⁹ Carbon emissions from fossil fuel use in the building sector constitute 12 percent of total U.S. GHG emissions, while carbon emissions from fossil fuel use in the industrial sector are responsible for 27 percent.¹⁰

The Potential Role of Natural Gas Networks in a Low-Carbon Future

While electrification will play a key role in decarbonizing the economy, gaseous forms of energy as well as the underlying natural gas infrastructure can play a critical complementary role in delivering renewable and low-carbon fuels reliably and cost-effectively to sectors across the economy. Decarbonized gas networks that deliver low-, zero-, and negative-carbon fuels (including RNG, hydrogen, and synthetic natural gas) can provide value in a low-carbon energy system in the following ways:

- **Energy storage:** By repurposing the gas networks, the long-term, large-scale energy storage capacity of gas networks can be used to store and deliver large volumes of low-carbon fuels.
- **Enhanced reliability and resilience:** Maintaining gas infrastructure alongside an electricity system adds a layer of resilience compared with an approach that relies exclusively on electricity.
- **Meeting peak load and enhanced flexibility:** Gas networks can continue to play an essential role in meeting peak energy demand all throughout the year, not only for gas networks, but also electricity (by supplying fuel for electric generation). Gas can continue to support increasing amounts of variable renewable resources on the electricity grid by providing a dispatchable energy source that can be “turned” up and down depending on renewable electricity generation.
- **Reducing electric system costs:** Ensuring electric reliability amidst high levels of electrification and renewable penetration will require significant investments to expand generation and the electric grid. Continued use of the gas infrastructure can help reduce the amount of build-out required.
- **Mitigation options for hard-to-abate sectors:** Certain industries require high-temperature process heat that is not easily electrified. The gas network can supply gaseous forms of energy to end-users that face technical barriers to electrification.

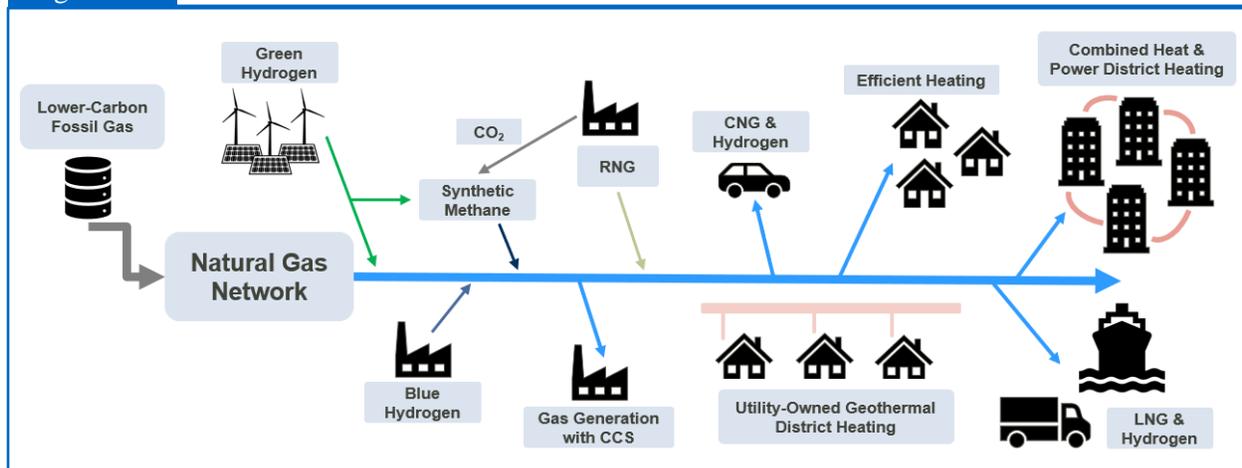
Natural gas networks can also be used to scale the deployment of low-carbon fuels in other sectors across the economy. The widespread use of low-carbon fuels requires a transportation and storage network to enable the transfer of these fuels from one sector to the next. Several studies have noted that the use of hydrogen across multiple sectors will help to achieve further cost declines and efficiencies, which in turn will help to achieve widespread commercial deployment.¹¹ By repurposing and utilizing existing infrastructure, multiple sectors can begin to deploy low-carbon fuels while avoiding significant upfront investments in transmission and distribution.

This concept is actively being explored through the development of “hydrogen hubs”—locations that have existing pipeline infrastructure and storage and are located near access points for use in multiple sectors—as a gateway to the development of the hydrogen economy. These hubs take advantage of the existing developed infrastructure to transport and store hydrogen and other low-carbon fuels for use within other sectors. Several coastal industrial hub projects have been announced in the United States, United Kingdom, and Australia.¹² Many of these focus on hydrogen blending for industrial applications in

ⁱⁱ For example, National Grid in partnership with several companies announced a plan to develop a hydrogen hub, the Drax Humber Cluster, in the United Kingdom. The project would produce hydrogen from natural gas and would use National Grid’s dedicated grid to transport the hydrogen for use in heating, transportation and industrial sectors. The project would capture the CO₂ and store it using bioenergy with carbon capture and storage (BECCs) in order to achieve its goal of being the world first net-zero industrial cluster by 2040. For more information, see: https://www.drax.com/press_release/energy-companies-announce-new-zero-carbon-uk-partnership-ccus-hydrogen-beccs-humber-equino-national-grid/.

near-term and have longer-term goals of expanding to supply hydrogen to the transportation and heating sectors. Existing natural gas infrastructure may also be important for transporting hydrogen that is produced in isolated areas to where it will ultimately be utilized.¹²

Figure 3 The Potential Role of Natural Gas Networks in a Low-Carbon Future



Designing a low-carbon transition that is equitable and affordable

As the manner in which space and water heating demand is met changes—with increased amounts of energy efficiency, electrification, and low-, zero-, and negative-carbon gases—gas customers and throughput are projected to decline. Remaining gas customers may face higher rates as they begin to take on a larger share of the fixed costs associated with maintaining a safe and reliable gas network. It will be important to plan and coordinate this low-carbon energy transition to ensure that remaining gas customers, especially disadvantaged and low-income customers, are not burdened with higher energy costs. In order to ensure an equitable transition, it is critical that key stakeholders from across the gas and electric sectors (including utilities, policymakers, regulators, consumer advocates, low income, and environmental justice groups) coordinate and work together to best manage these potential impacts through strategies and policies that are consistent with climate targets.

An analysis by Gridworks and E3 in 2019 found that residential rates in California could increase from their current rate of \$1.3 per therm to up to \$18 per therm in 2050 if no comprehensive gas transition strategy is deployed and only 2 million customers utilize the gas grid. The same analysis found that residential rates as low as \$4 per therm are possible with the same level of customer loss if a comprehensive gas transition strategy—that evaluates and plans for targeted electrification and gas infrastructure decommissioning, in addition to evaluating where the utilization of the gas grid is more effective—is deployed. In taking a more integrated approach, gas and electric utilities will be better able to provide cost effective and low-carbon energy sources to their customers in the near-and long-term.

Local Distribution Company Strategies to Decarbonize Gas

Many of the characteristics of regulated LDCs present a unique opportunity to play a critical role in facilitating and accelerating the transition to a carbon neutral economy. As energy providers with an extensive engineering workforce, LDCs have the necessary expertise to plan, integrate, and manage the deployment of new technologies while maintaining safety and system reliability. LDCs also have an existing relationship with energy consumers, providing a trusted pathway for increased engagement to manage, reduce, and decarbonize energy use.

Just as the path to carbon neutrality will differ among states, regions, and provinces, the exact role of each LDC in decarbonization will also vary from utility to utility, depending on their unique asset and customer

base, regulatory and political climate, and geography and climate zone. However, there are likely to be similarities in the key features of most networks.

LDCs can build critical mass quickly through their customer base, strong governance, and proven operational effectiveness to help facilitate achievement of carbon reduction ambitions. To decarbonize their gas networks and accelerate the transition to a carbon neutral economy, LDCs can pursue three broad and integrated strategies:

- **help customers become more energy efficient** through building retrofits, advanced efficient technologies, and other emerging innovative technologies such as district heating, to reduce gas demand as well as total energy demand across the economy;
- **drastically reduce and eliminate methane emissions from their networks and operations** as well as throughout the full natural gas supply chain; and
- **supply customers with lower and zero-carbon sources of energy** by gradually repurposing the gas networks to supply increasing amounts of renewable energy, including RNG, hydrogen, and synthetic natural gas.

LDCs can prioritize the most impactful efforts, given their unique circumstances. It is also important to note the complementary nature of these strategies. For example, while low-carbon fuels are currently more expensive than natural gas, LDC efforts to reduce system demand through energy efficiency and other measures will not only reduce emissions associated with gas consumption, but also allow a utility to supply its remaining load with a larger percentage of low-carbon fuels for the same cost.

Figure 4 Technology Deployment for Gas Decarbonization and a Carbon Neutral Economy



To decarbonize their gas networks and contribute to decarbonization in their service territories, LDCs need to aggressively pursue the strategies discussed in this paper in tandem, while also seeking new partnerships, energy policies, and utility regulatory models. The following sections describe each of these three strategies, as well as examples of best practices from DSI members and other leading utilities, in turn.

Increasing Energy Efficiency and Optimizing Energy Use

One critical strategy to decarbonize gas networks is conserving energy and reducing natural gas consumption. Efforts to conserve energy are an important component of decarbonizing gas networks because they reduce not only total gas consumption (and associated emissions) but also peak demand: this can help alleviate pipeline constraints and therefore reduce or avoid the need for new gas infrastructure.

Some jurisdictions have begun evaluating revisions to the gas planning process to better consider and reflect potential strategies such as energy efficiency, electrification, and others to reduce energy use and meet customer demand without investments in new gas infrastructure.

While energy conservation on its own cannot enable deep decarbonization consistent with carbon neutrality, it can achieve significant reductions and complement parallel efforts to reduce methane emissions and transition to renewable fuels.

This section reviews the following strategies for LDCs to conserve energy, in partnership with customers and regulators:

- Accelerate aggressive energy efficiency and weatherization programs to help customers optimize their energy use;
- Pursue strategies such as demand response and load control to reduce peak system loads; and
- Provide customers with alternatives for low-carbon heat, including electrification and geothermal networks.

By employing these strategies, LDCs can pursue new low-carbon investments and take actions that drive down energy use and GHG emissions, in support of a highly-efficient, decarbonized future.

Energy Efficiency Programs

Energy efficiency programs are crucial tools for LDCs to manage and reduce energy consumption. In 2018, there were 125 natural gas energy efficiency programs spanning 42 states in the United States, as well as seven in Canada.¹³ Investing in energy efficiency reduces gas consumption, resulting in energy savings, avoided emissions, and reduced peak demand, while also avoiding the need for new energy infrastructure and lowering customer bills. Additional benefits of energy efficiency include enhanced user comfort and control, the creation of local jobs, and reduced air pollution.

Utility energy efficiency programs deliver these benefits by helping customers improve building envelopes and adopt more efficient natural gas appliances.¹⁴ Building envelope improvements can range from low-cost weatherization measures to save energy by sealing air and thermal boundaries (such as by weatherstripping doors and windows, installing more efficient windows, or increasing wall and attic

Case Study: Accelerating Energy Efficiency in New York

New York's Climate Leadership and Community Protection Act establishes ambitious targets to achieve a 40 percent reduction in statewide GHG emissions by 2030, below 1990 levels, and to achieve net-zero emissions by 2050. Energy efficiency will play a critical role in achieving New York's climate goals: the state estimates that energy efficiency will contribute roughly one-third of the emissions reductions needed to achieve the state's 2030 GHG reduction target.

To achieve these reductions through energy efficiency, New York's Public Service Commission (PSC) has adopted the following savings targets for utilities:

- Electric: Annual reduction of 3 percent in electricity sales by 2025
- Natural Gas: Annual reduction of 1.3 percent in gas sales by 2025
- Heat pumps: 3.6 trillion British thermal units (TBtu) in savings from the installation of heat pumps

The PSC's energy efficiency framework allows utilities, including DSI members Con Edison of New York and National Grid, to pursue cost-effective energy efficiency and electrification investments. These measures are projected to achieve 35.8 TBtu of incremental energy savings by 2025, on top of energy efficiency programs that have already been authorized. In addition to providing one-third of the emissions reductions needed to achieve the state's 2030 GHG reduction target, the PSC estimates that these savings will result in \$13 billion in gross bill savings to participants, \$6 billion in gross lifetime utility system benefits, and \$1.7 billion in societal carbon reduction benefits.

More information: New York PSC's December 13, 2018 and January 16, 2020 orders (Docket No. 18-00381).

insulation) to deep building energy efficiency retrofits. Programs commonly include a combination of financial incentives (such as rebates and loans for more efficient technologies) and technical services (such as energy audits, retrofits, and training for architects, engineers, and building owners). Energy efficiency programs can also include customer-focused educational campaigns about the benefits of energy efficiency.

Barriers to increased energy efficiency investment by LDCs include sustained low natural gas prices, cost-effectiveness tests, and existing rate structures. By modifying regulatory structures, state regulators can help address these barriers and provide a regulatory environment that incentivizes LDCs to increase their investments in energy efficiency. For example, regulators can provide LDCs with incentives for surpassing energy efficiency targets at levels that are commensurate with or exceed incentives currently offered for other investments (such as pipeline expansion).

Demand Response

LDCs can also implement demand response (DR) to reduce energy usage during peak periods. DR programs provide customers with incentives to reduce or shift their energy usage during peak periods in response to time-based rates or other forms of financial incentives, or by direct load control by the utility. While DR has been more commonly associated with efforts to manage peak electric demand on the hottest summer days, natural gas DR can also offer significant opportunities for utilities to manage peak natural gas demand, during the coldest winter days. For example, a decrease in thermostat temperature by only one degree during the winter could lead to a roughly 2 percent, or 40 MMcf/day, reduction in gas demand in New England, corresponding to significant energy and emissions savings.¹⁵

Reducing peak demand is an important strategy because it can help alleviate pipeline constraints and therefore reduce or avoid the need for new gas infrastructure. As is the case in the electric sector, peak gas demand largely dictates infrastructure requirements and associated investments. Lowering peak demand can also reduce energy costs by avoiding costs associated with supplying higher peak demand, as well as reduce energy consumption and associated GHG emissions. While some DR programs can be implemented without smart devices, smart thermostats provide for enhanced data and control, likely resulting in greater peak energy savings.

While natural gas DR programs have been less explored than their electric counterparts, initial DR programs and pilots from DSI members National Grid, Con Edison, and Southern California Gas (SoCalGas) have shown encouraging results. These programs provide incentives to customers that, during periods of peak demand, reduce their consumption of gas for heating (e.g., via thermostat control or water heater temperature settings for the residential and commercial sectors) or cease interruptible loads (e.g., through interruptible service or fuel switching, commonly in the commercial and industrial sectors). Another way to potentially achieve the goals of more formal DR programs is by modifying rate design to better recognize the costs of serving peak loads and incentivizing customers to reduce consumption during these periods.

Case Study: Con Edison's Demand Response Pilot

To address increased customer demand for natural gas in its service territory and limited transmission pipeline capacity, DSI member Con Edison is piloting a demand response program to understand the opportunity for customers to reduce usage on cold, peak gas demand days. Con Edison offers incentives for firm gas customers in certain zones to provide a net reduction in natural gas use over a 24-hour peak day (from 10am to 10am the following day).

The program contains two offerings: 1) a performance-based offering, available to commercial and industrial customers and multi-family buildings with centralized heating systems that can curtail gas consumption or reduce gas usage by switching to electricity or steam during events, and 2) a direct load control offering for small residential customers with smart thermostats. Two years into the three-year program, the pilot has provided Con Edison with valuable insights into DR opportunities for natural gas.

[More information:](#) Con Edison's Smart Usage Rewards for Reducing Gas Demand.

Advanced Efficient Natural Gas Technologies

Through their energy efficiency offerings, LDCs can accelerate the adoption of efficient natural gas end-use technologies for space heating, water heating, and cooking. A study conducted by the American Gas Foundation (AGF) in 2018 found that the adoption of more efficient emerging technologies could reduce U.S. residential natural gas emissions by 24 percent, with average net savings of \$51 per metric ton of carbon dioxide.^{iii,16}

New, more efficient natural gas technologies continue to be developed, including condensing hot water heaters and furnaces, natural gas heat pumps, hybrid heat pumps, and combined space and water heating systems. Smart thermostats are also offering energy saving opportunities. These technologies, highlighted in Table 1, are in various stages of research, development, and deployment.

Table 1 **Advanced Natural Gas End-Use Technologies**

Technology	Description
Condensing gas furnaces and boilers	Condensing gas furnaces and boilers are commercially available high-efficiency appliances for space and water heating. These technologies have an Annual Fuel Utilization Efficiency (AFUE) of 90 to 99 percent (compared to the AFUEs of 65 to 70 percent held by their non-condensing counterparts). Condensing appliances achieve these higher efficiencies by using a second heat exchanger to condense the water vapor in exhaust gases, thus recovering more of the energy released during combustion. These appliances also produce fewer NOx emissions than standard, non-condensing gas furnaces and hot water heaters.
Gas heat pumps	Gas heat pumps are a subset of heat pumps whose primary input energy is natural gas, instead of electricity, to power a compressor. While less common than their electric heat pump counterparts, there are a variety of gas-fired models, including those that use vapor compression, absorption, adsorption, and thermal compression. Gas heat pumps can provide both space and water heating and can often operate reversibly to provide cooling and heating with the same product. Gas heat pumps also operate efficiently in colder temperatures. ¹⁷
Combination gas space and water heaters	Combination heaters enable advances in gas heat pump, furnace, and boiler technology to be used to provide both space and water heating efficiently. Designed for residential and small commercial use, a wide variety of system configurations are coming to market. ¹⁸
Hybrid heating systems	Hybrid systems combine high-efficiency gas-fired appliances with an electric heat pump. An emerging technology, hybrid heating systems offer specific advantages over single-fuel heat pumps: because they can vary fuel supply depending on specific circumstances, they can operate more efficiently, reduce emissions, and lessen infrastructure impacts. For example, gas can be used during cold temperatures when electric efficiencies are sub-optimal or during peak electric load periods when electric costs and grid emissions are high. In this way, hybrid heat pumps offer opportunities to both reduce gas consumption and eliminate stress on the electricity network infrastructure during times of high thermal load. ¹⁹
Smart thermostats	Smart thermostats are critical resources to enabling demand response in addition to allowing users greater control over their energy consumption and comfort. Many smart thermostat products are commercially available including products from Nest, EcoBee, Honeywell, and others. A study by Enovation Partners found that smart thermostats, when combined with building envelope

ⁱⁱⁱ The study found that supporting policy further increases emission reductions: with higher levels of incentive support for emerging technologies, GHG emissions can be reduced by 40 percent, at an average cost of \$60 per MT CO₂.

Technology	Description
	measures, can deliver GHG emission reductions for residential and commercial buildings from 10 to 45 percent. ^{iv}
Hydrogen-ready appliances	Hydrogen-ready appliances are emerging technologies designed to operate on both natural gas and hydrogen. In recognition of efforts to integrate low-carbon fuels like hydrogen onto the distribution system, many entities are working to develop residential and commercial appliances, such as stoves, furnaces, and hot water heaters, that are “hydrogen ready.” Some of these appliances are intended for low levels of hydrogen blending, while others are designed to tolerate up to 100 percent hydrogen with no adverse impacts to the appliance. The installation of these appliances can help to advance integration of hydrogen into the gas networks by reducing the barriers of technology lock-in. ²⁰ Other entities are developing standardized conversion kits that could be used to readily convert natural gas-fired appliances to hydrogen equivalents.

Electrification

While there are unknowns regarding the exact paths to decarbonization, it is clear that electrification, when coupled with increasingly renewable and zero-emissions electricity, will play an important role in decarbonizing the economy. However, transitioning to a carbon neutral future will require a full suite of strategies. For example, LDCs and electric utilities will need to collaborate on electric and gas system planning and on innovative approaches for the benefit of customers, including electrification and low-, zero-, and negative-carbon gas supply to achieve emissions reductions (for example, see case study below on VGS’s partnership with the Burlington Electric Department). Electrification can also present unique opportunities for integrated utilities that serve both electric and gas customers.

In the buildings sector, two technologies gaining traction for electric space and water heating are air-source and ground-source heat pumps (ASHPs and GSHPs). ASHPs boast high efficiencies on average and the efficiencies of GSHPs are even higher given relatively constant underground temperatures. Achieving emissions reductions through electrification is also dependent on outside air temperature and the emissions intensity of the local power grid at the time of use. Depending on these factors, some technologies may already achieve emissions reductions, while others may require a cleaner electric grid than what is currently available. At the same time, many jurisdictions have established policies requiring electric utilities to deliver electricity generated from increasingly renewable and zero-carbon sources, with several states targeting 100 percent carbon-free electricity in the coming decades.²¹ Over time, these policies will reduce the carbon intensity of electricity in these areas, resulting in increasing emissions savings for customers who electrify.

While electrification is an important decarbonization strategy, there are also important challenges to consider. For example, the operational efficiency of ASHPs is affected by outside air temperature, with significantly reduced efficiency (and associated increased energy use, energy costs, and emissions) on very cold days. Although cold-climate ASHP technology is improving, in some circumstances it may be prudent for customers that switch to electricity to maintain a supplemental heating source to meet heating needs cost effectively on the coldest days of the year.^v There are also limits to how quickly and extensively electrification can occur: for example, certain industrial applications are not conducive to

^{iv} More information on smart thermostat emission reductions available at: https://www.aga.org/globalassets/research--insights/reports/ghg-reduction-pathways_phase-1-report.pdf

^v In field studies on cold-climate heat pumps, the Center for Energy and the Environment (CEE) found that heat pumps can supply about 60 percent of a home’s heat during a Minnesota winter. See: Schoenbauer, B. 2019. Field Assessment of Cold-Climate Air-Source Heat Pumps in Minnesota, CEE, available at [https://www.mncee.org/MNCEE/media/PDFs/86417-Cold-Climate-Air-Source-Heat-Pump-\(CARD-Final-Report-2018\).pdf](https://www.mncee.org/MNCEE/media/PDFs/86417-Cold-Climate-Air-Source-Heat-Pump-(CARD-Final-Report-2018).pdf)

electrification given their requirements for high-temperature process heat. Certain (commonly older) buildings may not be amenable to cost-effective electrification given building design, electric service capacity, legacy heating systems, and other site-specific considerations.

In addition, high levels of electrification from multiple sectors, including transportation, will significantly increase electricity demand. Replacing the energy that the natural gas network supplies, particularly on cold winter peak days, will require significant investments in electric generation, transmission, and distribution infrastructure. As policies in many jurisdictions require increasing levels of renewables over time, significant investments will be needed to ensure availability of flexible, dispatchable and affordable zero-carbon energy to meet demand at all times, including during peak periods. Expansion of the electric system would also need to overcome persistent challenges related to siting and cost allocation that frequently prevent (or severely delay) planned transmission infrastructure.

There are also important considerations about cost, affordability, and environmental justice. Electrifying requires homeowners and businesses to replace their heating systems and other appliances. The upfront costs for heat pump technologies are typically higher than conventional gas appliances, posing a burden or barrier for low-income customers. To offset this, some jurisdictions are providing financial incentives to encourage adoption; heat pump prices are also projected to decline.²² Once purchased, the economics of operating these technologies, relative to continued natural gas use, are influenced by seasonal energy needs related to climate zone (i.e., heating and cooling degree days), electric versus natural gas prices, and appliance efficiency. Widespread electrification could also increase costs for natural gas customers who do not electrify.

While electrification will play a key role in the transition to carbon neutrality, these challenges highlight the risks of pursuing electrification as the sole path to economy-wide decarbonization. Electrification policies must carefully weigh these concerns, evaluate alternative approaches, and consider the complementary role natural gas can play to reduce GHGs while minimizing costs and ensuring reliability.

Case Study: VGS's Energy Efficiency Partnership with Burlington Electric Department

In partnership with the Burlington Electric Department, DSI member Vermont Gas Systems (VGS) is offering a Net Zero Home pilot to assist residents in achieving their GHG reduction goals. The two utilities provide customers with an action plan that can be tailored to fit a customer's energy needs, goals, and budget to reduce their GHG emissions. Plans can include weatherization, equipment replacement, electrification options (including cold-climate heat pumps), RNG, and electric vehicle options.

Once customers receive a customized action plan, they can then receive financial incentives to reduce their energy use. VGS and BED provide up to a 50 percent incentive for weatherization projects, BED offers heat pump incentives for up to \$2,050, heat pump water heater incentives up to \$800; incentives are also offered for commercial buildings. The program also offers EE and weatherization standards for residential housing, energy efficiency training for architects and builders, provides zero energy modular home demonstrations, and offers a series of transportation electrification initiatives.

[More information:](#) VGS's 2050 Vision, Burlington Electric Department press release.

District Heating: Geothermal Networks

To transition to a carbon neutral future, LDCs can also explore opportunities to provide customers with alternative energy sources for low-carbon heat. One of these opportunities is district heating using geothermal networks. While ground-source heat pumps can serve a single building, a networked or shared loop system can provide heat and hot water to multiple buildings. In shared loops, connected buildings may be able to exchange heat among themselves. This load diversity can result in lower overall thermal capacity requirements, and thus a smaller required geothermal loop and energy input. Despite the emissions benefits of geothermal networks, barriers to adoption include the high upfront cost associated with designing, drilling, and installing the geothermal loop, combined with the typically long payback periods. For example,

proper selection and design of a geothermal system requires consideration of peak and annual building heating and cooling loads, as well as modeling of water and ground temperature. Local geological conditions, space availability, costs, and permitting also require consideration.

LDCs are well-positioned to make this technology more affordable to customers, given their access to low-cost capital and the ability to recover costs over long periods of time. LDCs are also well-positioned to support construction and oversee the long-term operation of geothermal ground loop infrastructure because gas engineers and construction personnel are already experienced in the design and installation of underground plastic pipe systems. Further, LDCs could play a crucial role in owning and managing geothermal systems, including using existing rights-of-way to run pipes and maintain the appropriate temperature and pressure within them.

Case Study: LDCs Explore District Heating Loops through Pilots

DSI member National Grid is exploring the potential of providing geothermal as a low-carbon source of heating to customers. To date, National Grid has tested two geothermal well systems, the first being a shared geothermal well system serving ten homes in a residential community and the second being a single geothermal well for a residential facility. Building upon these successes, National Grid has proposed to develop and implement a larger geothermal shared loop that would provide enough energy to serve roughly 650 single-family homes. Under this pilot program, National Grid would construct and own the shared loop infrastructure and provide thermal energy to connected customers under a long-term contract rate.

Eversource is also evaluating the potential of geothermal. In October 2020, the Massachusetts Department of Public Utilities approved an Eversource pilot program to test the feasibility of networked, utility-provided geothermal energy. The pilot will be conducted in a dense, mixed-use (residential and commercial) area and will study potential efficiencies of serving a mixed customer class with diverse loads. The pilot's budget of \$10.2 million includes the costs of drilling wells, internal labor, in-home equipment (e.g., heat pump units, distribution piping, ductwork), installation costs, and evaluations. Once installed, the participant will own and maintain all in-home equipment, and Eversource will own the geothermal network equipment outside the home (e.g., piping, pumps, control panels, and cooling towers).

More information: National Grid's Future of Heat testimony, Massachusetts DPU order approving geothermal demonstration project.

Reducing Methane Emissions Across the Value Chain

Reducing methane emissions associated with the entire natural gas value chain, from production through end use, is essential to achieve GHG emissions reductions in the near term and for the gas network to contribute to a carbon neutral economy over the longer term. LDCs can employ an array of strategies to reduce methane emissions associated with the gas they deliver through their networks. These policies and practices range from procuring lower-GHG natural gas from suppliers to making system improvements and operational changes that reduce methane emissions. They also include research and development (R&D) efforts to implement new methane detection technologies and sharing and adopting best practices.

While all of these strategies reduce the emissions intensity of natural gas delivered to customers, they do not reduce GHG emissions from end-use combustion that account for the majority of life cycle emissions. For example, the National Energy Technology Laboratory's most recent life cycle analysis of GHGs from natural gas used for power generation found that only a quarter of total GHG emissions occur between natural gas production and distribution, with the remaining three quarters from end use.²³ LDC efforts to reduce methane emissions from operations and throughout the full natural gas supply chain are therefore only a component of the natural gas utility industry's efforts to decarbonize. The strategies discussed elsewhere in this paper to reduce and decarbonize the fuel delivered to and used by customers are necessary to achieve a low-carbon future.

As LDCs seek to leverage the gas network to deliver low-, zero-, and negative-carbon gases, including RNG, synthetic natural gas, and hydrogen, it will be critical to ensure that methane emissions continue to decline. For example, as LDCs scale up RNG supply, methane emissions from production through end use will need to be accounted for and minimized to reduce the life cycle carbon intensity of supply. In addition, as blue hydrogen (hydrogen produced from natural gas with carbon capture and storage) comes online, methane emissions from natural gas inputs and the transportation and delivery of hydrogen will require a near-zero leakage rate.

The utility industry’s commitment to eliminate methane emissions has been highlighted in recent years by the announcement of aggressive methane reduction targets. Details on specific LDC voluntary commitments are provided in **Appendix A**.

The strategies outlined below are all being implemented by leading LDCs to facilitate the transition to a carbon neutral economy and achieve methane emission reduction targets

Infrastructure Modernization

LDCs are reducing methane emissions by updating aging infrastructure with modern equipment. While pipelines and related equipment are designed to last for decades, the legacy infrastructure in many utility service territories has been in use for more than half a century and lacks protection against corrosion and is leak-prone. As a result, older infrastructure tends to have higher methane leakage rates. Leading LDCs have implemented infrastructure modernization programs to reduce methane leaks and replace or repair systems before leaks occur. Infrastructure modernization programs also improve safety and reliability while supporting job creation and other economic benefits.²⁴

The primary means of updating gas utility infrastructure is through pipeline replacement, in which LDCs remove a utility’s most leak-prone (often the oldest) pipelines and replace them with modern pipelines. Given the costs of pipeline replacement, constraints on workforce availability, and the disturbances caused by digging up mains and services, pipeline replacement programs generally target replacing a set number of miles per year over a number of years until all or a percentage of leak-prone pipe is removed. Several LDCs have initiated accelerated pipeline replacement programs to replace leak-prone pipe at an even faster rate to minimize GHG emissions and reduce risk.

Leading LDCs are also reducing methane emissions from pipelines through use of cast-in-place liners^{vi} and cast-iron pipe joint sealing.^{vii} These practices allow utilities to reduce emissions from leak-prone pipelines more cost-effectively and without digging up the street and replacing the pipe.

A wide range of distribution infrastructure beyond natural gas pipelines can be modernized to reduce emissions while improving reliability and safety. These may include replacement of gas-driven pneumatic devices to air or electric, implementation of gas capture and reuse technologies at compressor stations, automated valves and automated isolation functionality, and installation of advanced gas metering infrastructure. When upgrading pipelines and other equipment, utilities can use hydrogen-ready materials to ensure the longevity of these investments and their ability to support increased blending of hydrogen into the natural gas system.

^{vi} Cast-in-place liner systems use robots to install structural coating materials inside existing pipelines, essentially creating a new pipeline within the existing pipeline. These systems can add decades to a distribution pipeline’s lifetime and new, more advanced technologies are currently being developed. See ARPA-E’s Rapid Encapsulation of Pipelines Avoiding Intensive Replacement (REPAIR) program: <https://arpa-e.energy.gov/?q=arpa-e-programs/repair>.

^{vii} Cast iron joint sealing is a technique used to eliminate leakage from the joints between pipeline lengths that can often be performed on active pipelines. Because leaks from cast iron pipelines are often caused by failed joints rather than cracks or holes in the pipeline itself, this process can significantly reduce emissions and extend pipeline life at lower cost than replacement or lining.

Case Study: NW Natural's Pipeline Modernization Program

Removing and replacing corrosion prone pipe is the largest opportunity for natural gas distribution companies to reduce fugitive methane losses. DSI member NW Natural was one of the nation's first utilities to remove or replace all known cast iron and bare steel pipes in its system with modern, corrosion-resistant piping. The final known bare steel was removed from the system in 2015 and cast iron pipe removal was completed in 2000. As a result of this accelerated pipeline replacement program, NW Natural's pipeline system today has a fugitive emission rate of less than 0.1 percent (using EPA subpart W reporting parameters).

NW Natural has also adopted industry best practices as recommended by EPA to reduce emissions from routine system maintenance. In 2016, NW Natural signed on as a founding member of the EPA's Natural Gas Star Methane Challenge. Under the program, NW Natural continues to adopt emission-reducing best practices associated with pipeline construction, maintenance, and repair.

More information: NW Natural; Natural Gas Distribution Infrastructure Replacement & Modernization: A Review of State Programs (NARUC, 2020).

Leak Detection and Repair

Targeted and more frequent pipeline leak surveying is a best practice that is increasingly being adopted by LDCs. Actively searching for natural gas leaks is another means by which leading LDCs reduce methane emissions. Research on methane emissions across the natural gas value chain, including distribution systems, has shown that a small number of leaks are responsible for a disproportionate percentage of total emissions.²⁵ By increasing the frequency with which pipelines and infrastructure are surveyed for leaks, these leaks can be identified and repaired sooner, significantly reducing their environmental impact. Eliminating larger leaks can substantially reduce total emissions. In the natural gas distribution segment, such large leaks may be quickly detected due to the presence of the added odorant, mercaptan in the gas and promptly fixed because they pose a safety hazard.^{viii} Larger leaks, therefore, usually exist for a brief period of time, minimizing their climate impact. However, leaks in unpopulated areas may go undetected for extended periods of time in between the less frequently required system surveys. Leaks classified as Grade 3 leaks, which can vary in size, may remain unrepaired for years because they do not pose a safety risk and are commonly not cost-effective to repair. While these leaks are small individually, collectively and over time, they can have a substantial climate impact.

LDCs can use advanced leak detection technologies including enhanced imaging and increasingly sensitive detection devices to discover unknown leaks and prioritize Grade 3 leaks for repair based on their size. One method to do this involves driving a vehicle outfitted with advanced methane detection equipment through a utility's service territory. Detected leaks can be flagged for more detailed follow up and emerging technologies are even allowing for increasingly accurate quantification using algorithms that convert the detector's methane concentration reading into a leak rate. Other survey methods include the use of drones with detection equipment and aircraft utilizing enhanced imaging. The more frequently surveys are made, the sooner unreported leaks are detected and repaired, minimizing methane emissions. Quantifying Grade 3 leaks allows utilities to identify those with the greatest climate impact and place them sooner in the repair queue schedule. A number of leading utilities have integrated advanced leak detection surveys into their operations and participated in initiatives to develop and test new technologies.²⁶ In addition, several states have begun implementing regulations that require LDCs to reduce their Grade 3 leak backlogs.²⁷

^{viii} Natural gas LDCs are required by law to survey, locate, classify, and fix leaks to maintain safety. Leaks are classified as follows: Grade 1 - A leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous. Grade 2 - A leak that is recognized as being non-hazardous at the time of detection, but requires scheduled repair based on probable future hazard. Grade 3 - A leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.

Case Study: PG&E's Grade 3 Leak Abatement Program

Studies indicate that a small number of leaks contribute disproportionately to methane emissions: a 2014 Washington State University study found that only 2 percent of leaks were greater than 10 scfh but accounted for 56 percent of total emissions. As such, accelerating leak detection and repair efforts for large leaks (defined as greater than or equal to 10 scfh) in a gas distribution system has the potential to substantially reduce methane emissions.

PG&E's Grade 3 leak abatement program does just that. Through this program, DSI member PG&E uses mobile leak detection technology (Picarro) to conduct annual surveys specifically targeting these larger leaks (by comparison, PG&E conducts a three-year survey cycle for all leaks). Once large leaks are identified, they can be repaired within days or weeks, as opposed to months or years.

[More information:](#) PG&E, Natural Gas STAR & Methane Challenge Workshop.

Network Operations

LDCs can implement operational practices to reduce methane emissions. Many utilities have been voluntarily implementing and sharing best practices for years through participation in EPA's Natural Gas STAR program. One of the largest reduction opportunities is from pipeline blowdowns, during which gas is removed from sections of pipe prior to maintenance. LDCs can do so by isolating pipeline segments, reducing pressure to minimize the volume of gas in the pipeline, transferring gas out of the pipeline via mobile compressors, and flaring any remaining gas. One or all of these best practices may be implemented, subject to technical feasibility and safety concerns. Other operational practices include engine maintenance to reduce emissions of uncombusted methane, capturing emissions from natural gas compressors, and targeted programs to reduce pipeline damages ("dig ins") by contractors and homeowners. These strategies improve safety and reliability while minimizing methane emissions and reducing the overall GHG intensity of natural gas delivered to customers.

Leading LDCs are also working to better understand their methane emissions by participating in academic and technology research and directly measuring methane emissions. GHG inventories, whether at the company or national level, have historically used default emissions factors and a count of activity or equipment to estimate emissions. Multiplying an emissions factor by its activity or equipment count yields an emissions estimate for a given type of equipment. While this provides a practical means of estimating emissions, it does not necessarily fully reflect actual emissions.^{ix} Uncertainties regarding the methane emissions from gas distribution infrastructure will persist if methodologies continue to focus on default emission factors, mileage, and equipment counts. In contrast, by directly measuring emissions wherever possible, or even developing company-specific emissions factors based on measurements from a subset of representative equipment, utilities and stakeholders gain a better understanding of the largest sources of methane emissions. This allows utilities to prioritize their efforts and address the highest-emitting infrastructure first.

Gas Procurement Standards

While LDCs have historically focused on reducing methane emissions from their own operations, they can also look upstream to source natural gas that is produced, processed, and transported with lower methane emissions profiles. These upstream sources are responsible for the majority of methane emissions from natural gas systems.^x Purchasing gas supplied by lower-emitting companies therefore allows LDCs to reduce the methane profile of the gas they deliver to customers. Contracting for lower-methane natural gas can meaningfully reduce methane emissions from the natural gas supply chain and drive improved environmental performance. These reductions generally represent a small percentage of life cycle GHG

^{ix} For example, based on the emissions factor approach, a brand-new plastic natural gas pipeline is leaking from the moment it is installed and has the same emissions profile as a plastic pipe installed three decades earlier.

^x EPA's most recent GHG Inventory estimated that the exploration and production, processing, and transmission and storage segments emitted 59, 9, and 24 percent of the industry's total methane emissions, respectively, in 2018. In comparison, natural gas distribution systems were estimated to be responsible for less than eight and a half percent of the industry's total methane.

emissions when end-use combustion is included. LDCs will need to source low-methane supplies for as long as there is traditional natural gas on their systems, but these efforts only complement long-term strategies to decarbonize the energy delivered to customers.

In recent years, increased industry and stakeholder concern regarding the environmental impact of natural gas production has driven research to better understand methane emissions and improved voluntary natural gas producer disclosures on key environmental metrics, particularly methane emissions and methane intensity. Additionally, producers have joined voluntary initiatives committed to reducing methane emissions and had their operations certified as meeting specific environmental criteria by third-party certification companies.

These developments are beginning to allow LDCs to differentiate the methane performance of their potential natural gas suppliers and inform supply decisions. A number of utilities have already integrated methane emission performance and other environmental criteria into their natural gas procurement processes.^{xi}

Natural gas procurement standards enable utilities to identify leading producers and purchase gas with a lower methane emissions profile. Coupling these purchases with contracts with low-emitting midstream companies that process and transport gas drives methane reductions throughout the natural gas supply chain. However, differentiated natural gas generally comes at a price premium. While the overall cost impact on ratepayers may be minimal, these higher costs may present a challenge to LDCs seeking supply and rate approvals from state regulators. As with other higher-cost decarbonization strategies discussed in this paper, state regulators will need to consider the GHG benefits of natural gas procurement standards and their contribution to policies such as state climate targets.

Natural Gas Supply Collaborative

The Natural Gas Supply Collaborative (NGSC) is a group of LDCs and power generators seeking to support safe and responsible practices for natural gas supply and encourage natural gas producers to voluntarily disclose information responsive to stakeholder concerns. NGSC has developed performance indicators on key environmental and social topic areas, including methane and total GHG emissions. Producer disclosures responsive to these metrics allow gas purchasers to evaluate the methane and GHG performance of upstream suppliers and prioritize contracts for lower-emissions natural gas. NGSC members are already incorporating the performance indicators into their supply requests and lowering the carbon intensity of the natural gas they use and supply to customers. NGSC is convened and managed by MJB&A.

More information about NGSC is available at: <https://www.mjbradley.com/content/natural-gas-supply-collaborative-0>.

Decarbonizing Gas Supply

To reach a carbon-neutral future, LDCs will not only have to take actions to reduce methane reductions and improve the efficiency of natural gas end-uses, but also will ultimately supply increasing levels of low-carbon fuels. Low-carbon fuels such as RNG, hydrogen, and synthetic natural gas offer the opportunity to decarbonize gas supply while using existing gas networks and allowing customers to keep similar, or in some cases, the same appliances. These resources can also provide lower-carbon energy to industrial users who require high-temperature process heat, which is more difficult to electrify than lower-temperature heat used for space and water heating in commercial and residential buildings.

More broadly, a gas network that delivers low-carbon and renewable fuels may help address other challenges for low-carbon energy systems. These resources can be used to supplement intermittent

^{xi} For example, in 2019, Virginia Natural Gas signed a two-year supply contract with Southwestern Energy to meet 20 percent of the utility’s demand. The gas is from Southwestern wells certified as meeting specific environmental standards by Independent Energy Standards, a third-party verifier. Further, all companies handling the gas, from Southwestern’s production to pipeline transmission through distribution by Virginia Natural Gas, are members of ONE Future, a coalition committed to reducing methane emissions across the natural gas value chain. In 2020, Énergir announced an agreement with Seven Generations Energy to supply “responsible” natural gas based on certification by Equitable Origin’s ESG standards and the disclosure of key environmental indicators.

electric generating resources with reliable, on-demand supply. With advances in technology, gas networks can also be used to store, on a seasonal basis, and deliver excess power produced by variable renewable resources. In this way, the gas networks can help to support increasing amounts of variable renewable resources on the electricity grid.

Decarbonizing gas supply requires a reconceptualization of the gas networks as infrastructure that can deliver a variety of low carbon gaseous fuels beyond conventional natural gas. Manifesting this transition is likely to require a transformative shift in the business model of LDCs, as well as how they are regulated. **Appendix B** provides details on natural gas utilities that have already committed to reducing emissions associated with the gas they deliver and thereby begin this transition.

Renewable Natural Gas

RNG is pipeline-quality gaseous fuel that can be derived from waste resources, such as animal manure, food waste, wastewater treatment plants, and landfills. Today, RNG is commonly produced via anaerobic digestion; over time, thermal gasification of woody biomass and other waste feedstocks is likely to play an increasing role in production. RNG has distinct benefits as a decarbonization strategy—because RNG has lower life cycle GHG emissions than natural gas and is made up of the same constituents as natural gas, it can be introduced into the gas distribution network safely and used by customers to reduce GHG emissions without any changes to existing equipment or appliances. In many regions, RNG can provide greater immediate GHG reductions at lower cost when compared to electrification of oil and conventional natural gas-fired appliances.²⁸ RNG production can also provide co-benefits such as water quality improvements and local economic development. For the industrial sector, RNG can be of particular value by allowing for immediate GHG emission reductions from heat-intensive industrial processes without changing existing manufacturing processes. Many high-temperature industrial processes can only be achieved via combustion using existing technology, highlighting the importance of low-carbon fuels such as RNG.

How Natural Gas Utilities Can Accelerate RNG Development

Interest in RNG has grown over the last several years, garnering increased attention from policymakers, regulators, stakeholders, and LDCs. While some stakeholders question the supply potential and GHG benefits of RNG, several states and LDCs are assessing the potential for RNG feedstocks and supplies in their states and service areas and are investigating the costs and benefits of integrating RNG into gas supply. LDCs can accelerate the incorporation of RNG resources into their natural gas systems through several mechanisms:

- **Voluntary programs:** LDCs can offer voluntary RNG programs, like voluntary renewable electricity programs, that allow customers to purchase a certain amount of RNG by paying a premium on their natural gas bill. The cost premium helps LDCs offset higher RNG commodity costs. Therefore, these programs allow customers to purchase a renewable fuel, provide the means for natural gas utilities to integrate RNG into their pipeline systems, and reduce the carbon intensity of their fuel supply in a manner that does not significantly increase costs for all customers.
- **RNG supply targets and standards:** LDCs can establish RNG supply targets, which set targets to procure a certain amount of RNG for blending into all base gas supplied to utility customers. Separately, renewable gas standards require utilities to meet RNG supply targets.
- **Interconnection guidelines and gas quality standards:** LDCs can also collaborate on RNG interconnection guidelines and gas quality standards. Guidelines and standards can improve safety and increase regulatory and financial certainty for utilities, developers, and customers.^{xii}
- **Public and private partnerships:** LDCs can also collaborate with large end-users (such as industrial facilities) and engage in public/private partnerships to develop long-term supply contracts

^{xii} For example, in August 2019, the Northeast Gas Association released a guide on RNG interconnection and gas quality. See: https://www.northeastgas.org/pdf/nga_gti_interconnect_0919.pdf.

with corporations and institutions to help them meet their energy needs in alignment with their sustainability goals.

Some LDCs are facing challenges obtaining regulatory approval of their efforts to accelerate RNG development. Regulators and legislators that recognize the environmental benefits of RNG can help establish incentives to procure, develop and integrate RNG into the supply mix.

Case Study: Voluntary RNG Programs

DTE Energy, FortisBC, and VGS have all launched voluntary RNG programs that allow customers to pay a premium to blend RNG into the fuel supply. These programs support decarbonization of the energy supplied by utilities at little to no cost to nonparticipating customers. FortisBC and VGS customers can select a percentage of their supply that will be met by RNG. Beginning in early 2021, DTE Energy customers can select from four different pricing options to reduce up to 100 percent of their carbon footprint. DTE's program uses both RNG and forestry-based carbon offsets as a means to lower emissions. Other voluntary RNG initiatives, such as one proposed by Southern California Gas and San Diego Gas & Electric, would allow residential customers select a pre-defined maximum monthly dollar amount for the purchase of RNG.

In addition to voluntary utility programs, several states have or are considering voluntary and mandatory renewable gas standards. These policies, similar to electric renewable portfolio standards, would allow utilities to blend specific amounts of RNG into the gas they deliver to customers. In 2019, the Washington and Oregon state legislatures passed laws that requires each gas LDC to offer RNG to its customers. In Oregon, up to 5 percent of a LDC's revenue requirement may be used to cover the incremental costs of RNG. The final regulation in Oregon sets goals for adding as much as 30 percent RNG by 2050.

More information: DTE, FortisBC, and VGS websites; Oregon RNG program.

Hydrogen and Synthetic Natural Gas

Hydrogen can be used as a feedstock, a fuel, an energy carrier, or as an energy storage medium, and has many possible applications across industry, transport, power, and buildings sectors. It also emits no end-use carbon emissions and almost no air pollution when used. It thus offers a solution to decarbonize the natural gas networks and industrial processes, as well as other difficult-to-abate sectors. These factors make hydrogen essential to support the transition to a carbon-neutral future.

There are several “types” of hydrogen, which are classified based on their production pathway:

- **“Green” hydrogen** is produced by zero-emitting electricity via electrolysis. When the electricity is sourced from the grid using a combination of generation sources and fuels the resulting hydrogen has lower life cycle GHG emissions than petroleum fuels, including natural gas.
- **“Grey” hydrogen** is produced from natural gas via steam methane reformation (SMR), which is the dominant source of hydrogen for industrial uses today.
- **“Blue” hydrogen** is produced from natural gas via SMR that is paired with carbon capture to capture most (commonly 95 percent or more) emissions.

Blue and grey hydrogen have lower life cycle GHG emissions than petroleum fuels, but not as low as green hydrogen, which is produced with a high percentage of zero emitting resources.

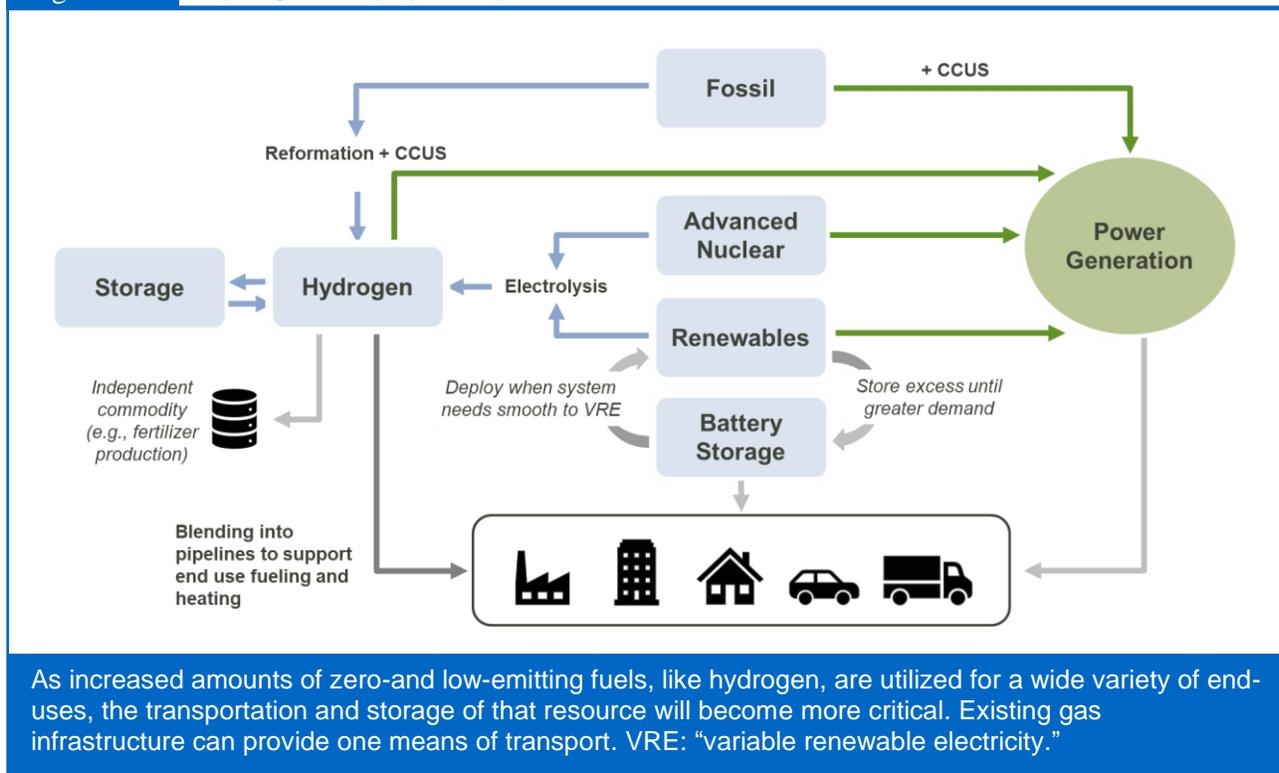
Hydrogen can be blended into pipeline systems or distributed through dedicated pipelines. Hydrogen blending is the injection of hydrogen into existing natural gas pipeline networks to reduce GHG emissions of natural gas end uses. Research efforts in Europe and elsewhere indicate that hydrogen can be blended up to 20 percent by volume without negative impacts on infrastructure or end use appliances.^{xiii} While less

^{xiii} HyDeploy is a project to demonstrate that hydrogen can safely be blended into the UK's gas grid without impacting the safety of end users or modifying appliances. The program consisted of three main elements: laboratory work; network appliance testing; and risk analysis—all leading to an exemption application to the Health & Safety Executive (HSE) to sanction the injection of hydrogen up to 20 percent. For more information see <https://hydeploy.co.uk/>

research on hydrogen blending has been conducted in North America to date, the U.S. National Renewable Energy Laboratory (NREL) announced in November 2020 that it will lead a new multi-year collaborative research and development project, HyBlend™, to address the technical barriers to blending hydrogen in natural gas pipelines.^{xiv, 29}

When combined with CO₂, hydrogen can also be methanated to produce pipeline-quality synthetic natural gas.

Figure 5 Hydrogen can play an important role in multi-sector decarbonization



How LDCs Can Accelerate Hydrogen Use

Shifting to gas supply that is largely or completely decarbonized will require technological advancements, new business models, and collaboration with many partners. Several lessons learned and best practices for LDCs to enable a transition to the use of hydrogen in gas networks can be gained from examining efforts in Europe, the United Kingdom, Japan, and Australia, where hydrogen has garnered increased focus.^{xv}

^{xiv} Research efforts will focus on 1) the compatibility of hydrogen blends on piping and pipeline materials; 2) life cycle analysis of emissions from using hydrogen blends and synthetic natural gas; and 3) techno-economic analysis of the costs and opportunities for hydrogen production and blending within the gas networks. The research team comprises six national laboratories and more than 20 participants from industry and academia. It will receive more than \$10 million in funding from the U.S. Department of Energy, with an additional \$4 to \$5 million of contributions from participants.

^{xv} Many countries have begun to evaluate ways to scale hydrogen use within electric, gas, and transportation sectors. Several countries—including the US, Germany, and the EU, among others have developed roadmap documents that outline a pathway for scaling hydrogen technology with some targeting hydrogen use within specific sectors. Others have provided funding resources to encourage research, development, and demonstration projects that test and scale different hydrogen production technologies and hydrogen utilization strategies. Notable examples include Australia’s Advancing Hydrogen Fund, a \$300 million dollar investment managed by the Clean Energy Finance Corporation (CEFC) to support hydrogen projects, and Germany’s National Innovation Program for Hydrogen and Fuel Cell Technology which provided over €1.6 billion in funding from 2008-2016, €250 million from 2016-2019, and €481 million from 2020-2022 to support the development of hydrogen and fuel cell technologies. While many of these funding sources have historically prioritized hydrogen deployment within the transportation sector (e.g., Germany’s funding primarily supports hydrogen and fuel cell technology within the transportation sector), a few countries have begun to take a close look at hydrogen blending opportunities within the heating sector. Notably, the UK has developed two funding programs that address both production and utilization project development to further deploy hydrogen within the UK’s heating sector. The Low Carbon Hydrogen

Case Study: Keele University's HyDeploy Project in the UK

The HyDeploy demonstration project is demonstrating that hydrogen can be safely blended into the natural-gas distribution system, as a strategy to reduce emissions, without requiring changes to appliances or disrupting end users. Beginning in January 2020, partners in the HyDeploy project began injecting increasing volumes of green hydrogen (produced via electrolyzer) into the university's existing natural gas network. At current blending levels of 15 percent by volume, users have been using the blend normally and have reported that they have noticed no difference. Blending levels will increase to 20 percent by the project's conclusion in March 2021. Once the Keele project is complete, HyDeploy plans to conduct larger demonstration projects on public networks in the UK. With regulatory approval and success at Keele, these phases will go ahead in the early 2020s.

The project is funded under Ofgem's Network Innovation Competition and is a collaboration between Cadent Gas, Northern Gas Networks.

[More information: HyDeploy.](#)

LDCs are working to enable a transition to the long-term use of hydrogen.

- **Hydrogen blending and interconnection efforts:** LDCs are conducting research and pilot programs to determine maximum hydrogen blending levels in their service territory – levels at which no- or minor- modifications would be needed for the distribution systems, customer meters, and customer appliances.
- **Hydrogen production and methanation efforts:** LDCs are working to produce low-, no-, and negative-carbon sources of energy that they can supply to customers. This includes proposals and efforts to construct electrolyzers to produce green hydrogen and/or to methanate hydrogen to produce pipeline-quality synthetic natural gas.
- **Public and private partnerships:** LDCs are working with government and academic institutions to test and accelerate efforts to deploy hydrogen into gas networks.

Case Study: Enbridge and Hydrogenics Markham Energy Storage Facility

The Markham Energy Storage Facility project—a joint venture between DSI member Enbridge Gas and Hydrogenics (now Cummins Inc) is a 2.5 MW power-to-gas energy storage facility located in Markham, Ontario Canada. It is the first major hydrogen energy storage facility in North America. The 2.5 MW facility was designed on a 126 m² footprint and can produce at peak 1000kg (12000m³) of renewable hydrogen per day and is scalable on the same footprint to 5 MW. The plant provides grid stability and reliability services throughout the region by providing frequency regulation to the Independent Electricity System Operator (IESO) of Ontario to help keep the electricity grid operating at 60hz. The project is one of several projects selected by the IESO to enhance grid reliability without the need for increased infrastructure development.

In December of 2019, Enbridge filed an application with the Ontario Energy Board (OEB) to conduct a pilot to blend up to 2 percent renewable hydrogen by volume in a select area of its natural gas distribution system serving approximately 3,600 customers. The pilot will enable Enbridge to validate its studies related to the benefits and challenges of blending hydrogen in the natural gas network, and is a first at scale in North America. The project was approved on October 30, 2020. Construction is scheduled to begin spring 2021 with blending commencing at the end of August 2021. Enbridge is exploring other opportunities for use of the hydrogen produced at the facility.

[More information:](#) Enbridge's proposed low-carbon energy project.

Supply Competition funds low carbon bulk hydrogen production projects and the Hydrogen for Heating project explores the feasibility of replacing natural gas with hydrogen for gas appliances. These funding opportunities have led to the deployment of a number of public-private partnerships between utilities, industrial entities and governments which have enabled the UK to test and better understand how hydrogen blending will impact existing gas infrastructure. While it may be too early to highlight lessons learned from many of these projects, their deployment marks an important step in demonstrating the technology for use within the heating sector.

Cost declines in the production, transport, and distribution of hydrogen, particularly of green hydrogen, are needed, as well as more research to better understand hydrogen embrittlement and leakage. Cost declines are projected to occur over time due to learning curves and economies of scale; natural gas utilities can also consider blue hydrogen in the near-term.

In the long term, it may be possible that the existing natural gas pipeline network could be repurposed to transport, distribute, and store 100 percent pure hydrogen, rather than natural gas as it does today. Alternatively, entirely new infrastructure could be developed to fulfill this purpose—transporting hydrogen from production sites to users across the energy sector. There are a variety of advantages and disadvantages to each of these options, and the most cost-effective choice will likely vary according to geography, distance, scale, and the required end use of hydrogen. Utilities are engaged in ongoing research efforts to determine how they can best facilitate the large-scale deployment of green hydrogen.

Case Study: SoCalGas and SDG&E Proposed Hydrogen Blending Demonstration Program

In November 2020, Southern California Gas (SoCalGas) and San Diego Gas and Electric (SDG&E) announced the creation of the Hydrogen Blending Demonstration Program. This program would be the first in California and among the first in the U.S. It was filed as part of a joint application to California Public Utilities Commission (CPUC) by SoCalGas, SDG&E, Pacific Gas and Electric (PG&E) and Southwest Gas in accordance with the Biomethane Order Instituting Rulemaking (Biomethane OIR).

The first proposed project will blend hydrogen into an isolated section of primarily polyethylene plastic distribution system in SoCalGas’s service territory, beginning at 1 percent by volume and potentially increasing to as much as 20 percent. SoCalGas expects to choose the location of the initial project in 2021. Subsequent projects are scheduled in SDG&E’s service territory and will build upon the knowledge learned in the first demonstration.

[More information:](#) SoCalGas and SDG&E press release.

Carbon Capture, Utilization, and Sequestration

Achieving carbon neutrality will also require additional strategies to remove carbon from the atmosphere, including CCUS, forestry and agriculture sequestration, and carbon offsets. CCUS—when paired with hydrogen production and use (e.g., SMR with CCUS) or RNG (e.g., bioenergy with carbon capture and sequestration (BECCS)—have the potential to: 1) enable near-term, low-, zero-, or negative-carbon alternative energy sources that can be used within heating, power, and transportation sectors and, 2) pave the way for new clean energy industries (e.g., a green hydrogen market) to scale and develop. As described in other parts of this paper, certain sectors of the economy will be slow and difficult to decarbonize (e.g., industries that require high-temperature process heat). CCUS will be especially critical for these sectors.

Other carbon sequestration strategies like direct air capture (DACs), which remove CO₂ directly from the atmosphere, and strategies to increase the carbon uptake of forests and soils, either through carbon offset mechanisms or other initiatives will be critical to removing and storing carbon from the atmosphere. BECCs, SMR with CCUS and DACs will rely on a combination of geologic storage and pipeline infrastructure in order to transport and store hydrogen and CO₂ for later use.^{30, 31}

Utilities can further advance these strategies through collaboration with technology developers, leveraging and repurposing existing infrastructure and right of ways, and engaging customers with new services and offerings. For example, carbon removal technologies, including carbon capture from large CO₂ emitting sources (such as electric generation facilities) and DACs will require transmission infrastructure to move CO₂ from the point of capture to the point of use and/or underground storage. Natural gas utilities can repurpose their networks for CO₂ or other low-carbon fuels produced with carbon

capture. Some are even equipped with short- and long-term storage opportunities and direct connections with industrial customers that could utilize the captured CO₂ for manufacturing processes. Finally, captured CO₂ from the industrial and power sector could serve as feedstock replacements in other industries and can be used to methanate hydrogen.

Case Study: CenterPoint's CleanO2 Pilot

CenterPoint Energy is working with CleanO2 Carbon Capture Technologies on a 12-month research pilot in Minnesota to monitor and measure the energy savings and CO₂ reductions that light industrial and commercial companies experience using the CARBiNX device. CleanO2's CARBiNX device takes a portion of waste flue gas containing CO₂ and passes it through a chamber, where it reacts with a carbon-reduction chemical to create pearl ash. The unit operates as a heat exchanger, using the heat generated from flue gas and the chemical process to preheat a building's domestic water supply, saving energy because it requires the boiler and/or water heater to use less natural gas. Each CARBiNX device can create up to 14,000 pounds of pearl ash per year, according to CleanO2. This safe and nontoxic byproduct can be used to manufacture a variety of products, including detergents and soaps, agricultural goods and textiles, among others.

[More information:](#) CenterPoint's CleanO2 Carbon Capture program.

Conclusion

The transition to a decarbonized economy is a significant undertaking. Today, natural gas and the natural gas distribution system play a critical role in North America's energy mix, supplying roughly one third of total primary energy demand and delivering roughly three times more energy on the coldest day of the year than the electric grid does on the hottest. However, economy-wide fossil fuel consumption must drastically decline over the next several decades in order to achieve long-term GHG emission reduction goals.

While the low-carbon energy transition represents an enormous challenge, it also provides a unique opportunity for LDCs to decarbonize their operations and to provide services that align with a carbon-neutral future. Gaseous forms of energy that can be stored over long periods of time, as well as the underlying natural gas infrastructure, can play a critical complementary role in delivering renewable and low-carbon fuels reliably and cost-effectively.

To decarbonize their gas networks and accelerate the transition to a carbon-neutral economy, LDCs can pursue three broad and integrated strategies: 1) helping customers become more energy efficient through building retrofits, advanced efficient technologies, and other emerging innovative technologies such as district heating, to reduce gas demand as well as total energy demand across the economy; 2) drastically reducing and eliminating methane emissions from their networks and operations as well as throughout the full natural gas supply chain; and 3) supplying customers with lower and zero-carbon sources of energy by gradually repurposing the gas networks to supply increasing amounts of renewable energy, including RNG, hydrogen, and synthetic natural gas. By repurposing the gas networks to transport low-carbon fuels, this infrastructure, as well as the workforce to maintain it reliably and safely, can play a long-term role in enabling a carbon-neutral economy.

Actions to reduce GHG emissions are accelerating but will need to increase in pace and scale throughout North America and the rest of the world to achieve long-term targets. Deep decarbonization will also require multiple technologies and strategies to address the myriad of energy demands and heating needs across key sectors including transportation, buildings, and industry. Additional strategies and technologies will also be needed to remove carbon from the atmosphere, including CCUS, forestry and agriculture sequestration, and carbon offsets.

Through DSI, LDCs are collaborating to build this shared vision for the role of utilities and the gas distribution network in the transition to a low-carbon future and are advancing strategies for LDCs to reduce GHG emissions and enable the transition to carbon neutrality. In collaboration with DSI, MJB&A is undertaking an assessment of the electric and natural gas system costs of achieving a carbon-neutral economy, with a focus on the role of gas networks. This includes an assessment of electric and natural gas utility costs of a greater role for energy efficiency, increased supply of renewable energy resources, and integration of the electric and gas networks over the longer term to achieve decarbonization goals. In developing this analytical assessment, MJB&A is conducting original research and analysis, facilitating discussions among members of the Downstream Natural Gas Initiative, and soliciting input from a multi-stakeholder Advisory Group. The results of this effort will be shared with stakeholders in 2021 to inform decarbonization planning and actions.

Appendix A: Natural Gas Utility Methane Reduction Goals

In recent years, several natural gas utilities, including many DSI members, have announced voluntary goals to reduce methane emissions from their operations.

Company	Goal	Scope
Atmos Energy	50% methane reduction from 2017 levels by 2035	Distribution system
Consolidated Edison	82% methane reduction from 2016 levels by 2036	Distribution system
Consumers Energy	Net-zero methane by 2030	“Delivery system”
Dominion Energy	65% methane reduction from 2010 levels by 2030, 80% reduction and net-zero GHGs by 2040	Production through distribution
DTE Energy	Net-zero methane by 2050	Storage, transmission, city gate, and distribution
Duke Energy	Net-zero methane by 2030	Distribution system
Enbridge	35% GHG intensity reduction from 2018 levels by 2030, net-zero by 2050	All operations
Eversource	Net-zero GHGs by 2030	All operations
Peoples - Essential Utilities	50% methane reduction, no baseline or target year specified	Distribution system
Peoples’ Gas - WEC Energy	30% methane intensity reduction from 2011 levels by 2030	Distribution system
National Grid	60% methane reduction by 2035 (baseline not specified), net-zero methane by 2050	Distribution system
NiSource	50% methane reduction from 2005 levels by 2025	Distribution mains and services
Spire	53% methane reduction from 2005 levels by 2025	Distribution system
Southern Company	50% GHG reduction from 2007 levels by 2030, net-zero by 2050	All gas and electric operations
Washington Gas & Light Co.	18% GHG intensity reduction from 2008 levels by 2020 (achieved)	Distribution system

Appendix B: Natural Gas Utility Scope 3 GHG Reduction Goals

Natural gas utilities, including DSI members, have also announced targets pertaining to Scope 3 emissions. Scope 3 GHG targets relate to reducing emissions from customer end use. These emissions comprise the majority of GHGs from the natural gas life cycle.

Company	Goal
CenterPoint	20-30% net reduction in CO ₂ emissions from 2005 levels by 2040
DTE Energy	35% reduction in GHGs from 2005 levels by 2050
National Grid	Net-zero GHG emissions by 2050
NW Natural	30% reduction in GHGs from 2015 levels by 2035, carbon neutral by 2050 (goal applies to customer emissions as well as company operations and distribution system)
Vermont Gas	30% reduction in GHGs from 2015 levels by 2030
Washington Gas & Light Co.	50% reduction in GHGs from 2006 levels by 2032, net zero by 2050

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