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Diverging Paths For Natural Gas

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Executive Summary

Natural gas long has benefitted from its reputation as the cleanest of the fossil fuels, with far lower carbon intensity than petroleum products or coal. Utilities concerned about limiting emissions have swapped coal-fired power plants for cleaner-burning natural gas generators. Some medium and heavy-duty vehicle fleets switched from diesel to compressed natural gas. Some industrial applications have shifted from petroleum-powered equipment to that fueled by natural gas. As a result, demand for natural gas is unlikely to decline as quickly or as steeply as that of other fossil fuels as the world attempts to slow climate change. Demand for natural gas is expected to continue to grow over the next few decades, driven by efforts in the developing world to both increase access to energy and to replace coal and other, dirtier energy sources with gas. But natural gas already is facing headwinds in the energy transition. Demand in the United States and other advanced economies is plateauing as part of the move to electrification powered by clean energy sources, including solar, wind, and nuclear. Natural gas markets themselves are changing, reflecting both current interest in and anticipated future demand for cleaner forms of natural gas.

That will take a variety of forms, from efforts to reduce CO_2 and methane emissions both at the wellhead and throughout the fossil natural gas value chain to new, lower emission forms of natural gas, including renewable and synthetic gas. Building these markets to sustained commercial viability will require advances in technology, reductions in cost, and new policies and incentives. For now, the market for differentiated natural gas – gas produced and sold in a way that allows its CO_2 and methane emissions to be accurately measured and minimized, generally certified by a third-party review – is small. Customer demand will have to be nurtured through both regulatory demands and policy support and other mechanisms that can lower the price to better compete with higher emission fossil natural gas.

Natural gas is made up primarily of methane, a powerful greenhouse gas and a potent contributor to global warming, along with ethane, propane, and butane. The United States is the world's largest producer of fossil natural gas, and gas supply chains are responsible for 8% of all U.S. greenhouse gas emissions and one-third of all methane emissions. While the CO_2 emissions from burning fossil natural gas are fairly consistent across sources, CO_2 and methane emissions along the fossil natural gas supply chain can vary considerably. There are steps that can limit emissions, such as reducing flaring, installing leak detection and repair systems to minimize fugitive emissions, and purchasing low-carbon electricity to power some functions rather than relying on burning natural gas. But non-fossil forms of natural gas could play a bigger role in the future. Renewable natural gas, also known as bio-methane, is the best-known and largest category of low-carbon non-fossil natural gas, a purified form of biogas generated from waste. It is virtually indistinguishable from fossil natural gas and can serve as a replacement for fossil natural gas without modifications.

There are four major production lines for renewable natural gas, based on different waste feedstocks:

• **Landfill waste.** Biogas captured from landfills is the cheapest source and represents about 70% of renewable natural gas feedstock in the U.S.

• **Agricultural manure.** Manure from dairy cattle, swine, and chickens can be converted to biogas and makes up about 20% of U.S. renewable natural gas.

• **Food waste.** Low supply of separated organic wastes has limited this source to 5% of the U.S. market.

• **Wastewater treatment.** Organic residues can be converted to renewable natural gas, currently accounting for another 5% of the market.

Costs remain substantially above that for fossil gas, and renewable natural gas currently represents less than 1% of natural gas production; its long-term potential is limited by the availability of feedstock.

A second option is synthetic methane or e-methane. It is synthesized from captured carbon dioxide and low carbon hydrogen, producing methane and water. The emission intensity of synthetic natural gas depends primarily on the source of the captured CO_2, as does the cost; synthetic natural gas can be about 10 times more expensive to produce than fossil natural gas. As with renewable natural gas, tax credits and other incentives, including those offered through the Inflation Reduction Act in the United States, can lower the cost. Globally, some governments are considering taxes on the carbon emissions of imported LNG, which would increase gas prices in countries where the taxes are imposed. That could accelerate the shift to low carbon gas and is likely to lead to a bifurcated LNG market – one market for premium, low carbon gas and one for traditional, higher emission gas. Building that market depends on smart, careful policy development, including pricing and taxation; subsidies; regulations including bans, phase-outs, mandates, and performance standards; and rules requiring disclosure and labeling.

Already, the European Union has launched policies to support the use of low carbon intensity natural gas, setting controls on the carbon dioxide emitted by the end users of fossil fuels and beginning work to collect data on methane emissions. The EU's Renewable Energy Directive also sets requirements for the use of renewable energy, including advanced biofuels. In the United States, the Inflation Reduction Act authorized the Environmental Protection Agency to implement the Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems to cut methane emissions, and the agency has proposed an annual waste emissions charge on methane emissions from oil and natural gas facilities that exceed specified levels. Another potential policy that could boost the move to lower carbon natural gas at the state level would allow regulated utilities to recover the cost of differentiated gas adoption, waiving typical requirements to purchase lowest cost gas.

Background

Natural gas has traditionally been marketed as a commodity. Commodities are resources, extracted or grown, that are standardized and hence easy to exchange for goods of the same type. Their prices are largely determined by supply and demand fundamentals, and they generally have a uniform price around the world, excluding transportation costs and taxes[1]. As a commodity, natural gas is valued strictly by location and delivery date in the cash or spot market and on organized exchanges as futures contracts. In addition to location and delivery dates, the value of gas sold under term contracts also reflects contract duration, pricing index, reliability of supplier, offtake flexibility, and contribution to the buyer's diversity of supply.

The three most developed demand centers for natural gas are Western Europe, North America and north Asia. These regions have dense pipeline networks and high demand for natural gas[2].

The deregulation of natural gas wellhead prices in the late 1980s and early 1990s revolutionized the U.S. natural gas industry and transformed the wholesale natural gas market. As a result, there are dozens of natural gas trading hubs in the United States. By far the most dominant is the Henry Hub in Louisiana. Henry Hub is strategically situated in a major onshore production region (the Eagle Ford, Haynesville, and Permian basins) and is also close to federal offshore production. Henry Hub also has significant connectivity to storage facilities and to intrastate and interstate pipeline systems. In April 1990, the New York Mercantile Exchange introduced the Henry Hub Natural Gas futures as the first standardized natural gas futures contract. Other U.S. natural gas locations are typically priced at a differential to Henry Hub to account for regional market conditions, transportation costs, and available transmission capacity between locations.

In Western Europe, the two most important regional hubs are the National Balancing Point or NBP in the United Kingdom and the Title Transfer Facility or TTF in the Netherlands. There are futures contracts based on both the NBP and TTF.

Until recently there has been no major spot market trading and price benchmark for natural gas in Asia because there are few pipeline connections between countries. With increasing LNG imports, a spot market has begun to develop, and Platts now assesses the north Asian LNG price through its Japan/Korea Marker or JKM index.

Natural gas is likely to have the best future prospects of the fossil fuels in terms of minimizing demand decline during the energy transition, given that it has the lowest relative carbon intensity of the three fossil fuels. The CO_2 intensity of natural gas is about 53 kilograms of CO_2 per million metric British thermal units (MMBTU), vs. 70-75 kilograms per MMBTU for the main petroleum products (gasoline, jet fuel, and diesel) and approximately 100 kilograms per MMBTU for coal[3]. Methane is also a great hydrogen carrier.

However, there is increasing concern about greenhouse gas (GHG) emissions in the fossil fuel value chains, including that for natural gas. While the CO_2 emissions from burning fossil natural gas are fairly consistent across sources, the CO_2 and methane emissions along the fossil natural gas supply chain, from production through delivery, vary considerable depending on the source. In addition, new non-fossil sources of methane with lower carbon intensities (combining CO_2 and methane emissions) are emerging. Each of these can leverage the extensive natural gas distribution networks today around the world and potentially jump-start a hydrogen economy. As a result, customers now have the option to choose among different sources of natural gas with different carbon intensities, and some have become more interested in the carbon intensity of the gas they purchase. As a result, natural gas may become further differentiated beyond location and timing.

Symposium Focus

The Gutierrez Energy Management Institute in the C. T. Bauer College of Business at the University of Houston held a symposium and workshop in May 2024 on the potential for diverging paths for natural gas as a result of the transition to a low carbon energy system. The focus was on the major sources of differentiated (lower carbon intensity) natural gas and derivatives, potential key buyers and suppliers, the likely challenges of developing differentiated gas markets, and government policies that will impact the development of these markets. The session included a keynote presentation, followed by panel discussions and small group discussions of key questions.

Participants included high-level energy executives, academics, and other energy thought leaders, with sessions conducted under the Chatham House Rule, used around the world to encourage inclusive and open dialogue in meetings. Its guiding spirit is to share the information you receive without revealing the identity of the source of the information or that of other participants.

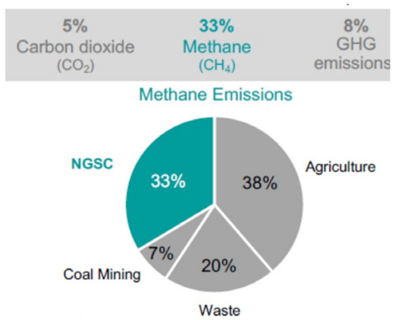
This white paper is based on information from the symposium, along with additional research.

GHG Emissions from the Natural Gas Supply Chain

Carbon dioxide and methane emissions along the natural gas supply chain make up a significant share of greenhouse gas emissions in major gas producing countries. Global Warming Potential (GWP), an index used to measure the relative climate impact of a given greenhouse gas, allows comparisons of the warming impacts of different gases. Specifically, it is a measure of how much energy the emission of one ton of a gas will absorb over a given time period relative to the emission of one ton of CO_2. Methane, the largest component of natural gas, is estimated to have a GWP of 27-30 over 100 years, although methane emitted today lasts about a decade on average, a much shorter time than carbon dioxide emissions[4].

The U.S. is the world's largest natural gas producer, and natural gas supply chains are responsible for 8% of all GHG emissions (GWP 100 Years) and 33% of all methane emissions (Figure 1). In terms of GWP, methane and CO_2 emissions are roughly equal on a 100-year basis, but methane emissions are responsible for nearly three quarters of GWP on a 20-year basis[5].

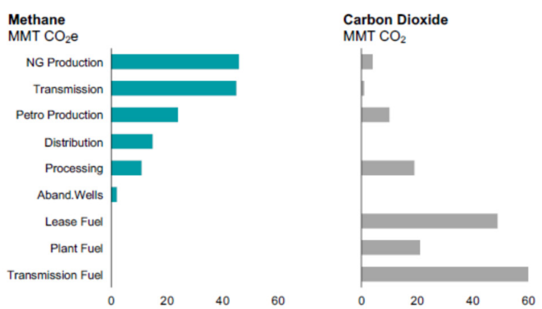
Figure 1: Percentage of U.S. GHG Emissions from Natural Gas Supply Chain



Source: Charting The Course: Reducing GHG Emissions from the U.S. Natural Gas Supply Chain - Natural Petroleum Council (April 2024).

Along the U.S. natural gas supply chain, fuel use makes up the largest source of CO_2 emissions, while the largest sources of methane emissions are production and transportation facilities (Figure 2).

Figure 2: Sources of U.S. Natural Gas Supply Chain GHG Emissions

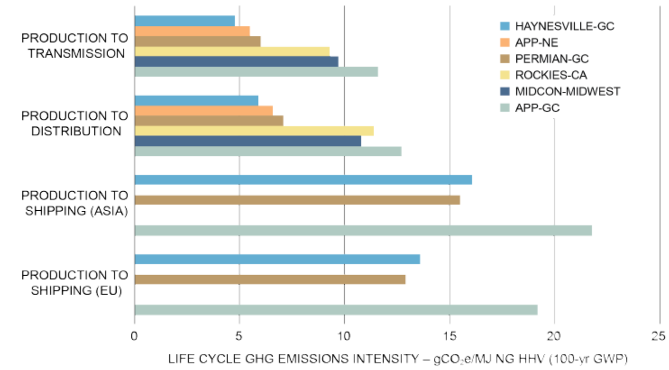


Source: Charting The Course: Reducing GHG Emissions from the U.S. Natural Gas Supply Chain - Natural Petroleum Council (April 2024).

Differentiated Fossil Natural Gas

The carbon intensity of current natural gas production around the world varies significantly. An analysis of 47 large global gas fields showed a range of a factor of five between the lowest and highest life cycle carbon intensity[6]. In the U.S., the most important domestic and international natural gas supply chains linking major production basins to major markets have varied life cycle GHG emissions (Figure 3).

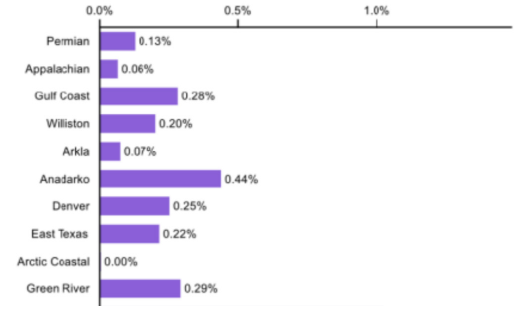
Figure 3: Life Cycle Emissions of U.S. Gas Supply Chains



Source: Charting The Course: Reducing GHG Emissions from the U.S. Natural Gas Supply Chain - Natural Petroleum Council (April 2024).

In terms of methane emissions only, analysis of the EPA's 2022 Greenhouse Gas Reporting System data shows that the range of methane emissions intensity from the 10 largest U.S. hydrocarbon basins varies from 0 to 0.4% (Figure 4), although several basins in the top 20 emit 1% or more.

Figure 4: Estimated Methane Intensity of Natural Gas Production in Largest U.S. Production Basins

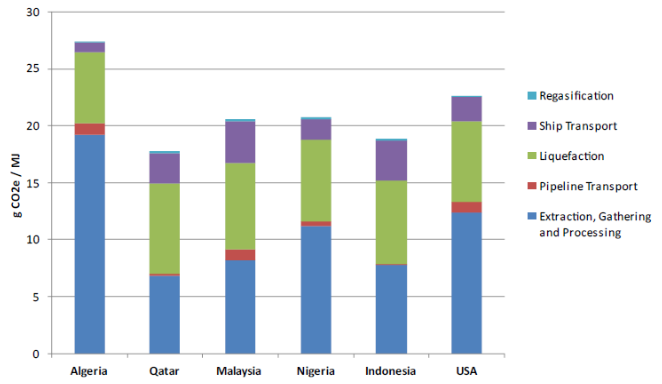


Source: Benchmarking Methane and Other GHG Emissions of Oil and Gas Production in the US – ERM (June 2024)

Other sources estimate significantly higher emissions. Based on overflights of parts of a dozen fossil fuel basins that account for nearly three quarters of onshore oil and gas production in the continental U.S., the Environmental Defense Fund estimates that around 1.6% of gross gas production is released into the atmosphere as methane. Individual basins ranged from 0.94% to 7.8%[7].

In term of internationally traded natural gas, differences in emissions along the supply chain result in very different relative carbon intensities of gas delivered to importing countries. For example, in terms of liquified natural gas imports to Germany, Algerian LNG has the highest carbon intensity, even though it is geographically the closest major source of LNG. This is due to high upstream emissions in Algeria. Given LNG's growing role in international trade vs. pipeline gas, more gas importers will have more choices about the source of their gas and have more ability to differentiate and diversify their purchases. (Figure 5)

Figure 5: Carbon Intensity of German LNG Imports - gCO_2e/MJ

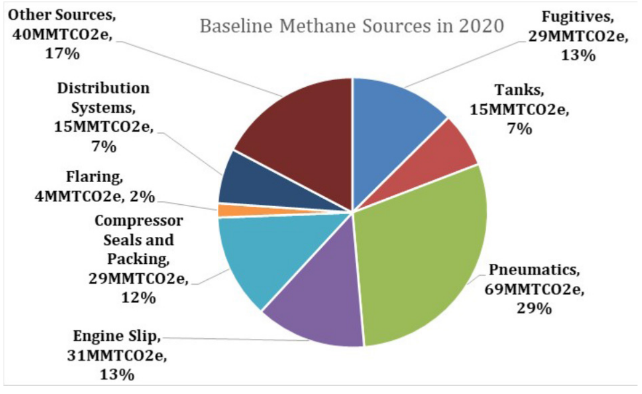


Source: Analysis of the greenhouse gas intensities of LNG imports to Germany - Institute for Energy and Environment Heidelberg (June 2023).

Reducing Fossil Gas Carbon Intensity

There are a number of ways for fossil gas producers to reduce their carbon intensity[8]. The largest sources of methane emissions in the natural gas supply chain are shown in Figure 6.

Figure 6: Sources of U.S. Natural Gas Supply Chain Methane Emissions



Source: Charting the Course: Reducing GHG Emissions from the U.S. Natural Gas Supply Chain – National Petroleum Council (April 2024)

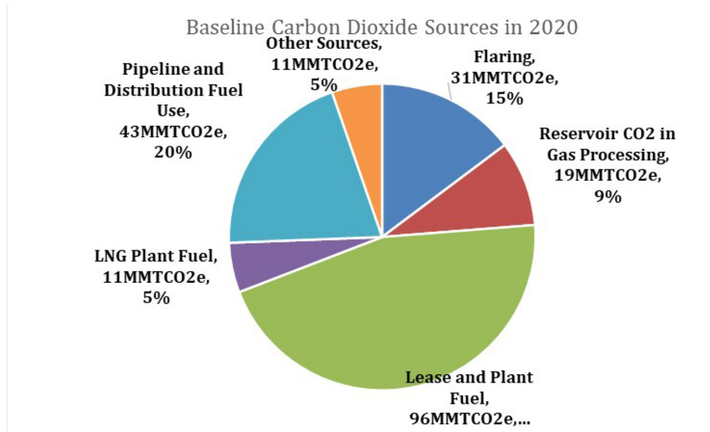
There are abatement options to reduce emissions from these sources (Table 1):

Key Source	Challenge	Abatement
Pneumatic Controls	Many natural gas production facilities use natural gas for pneumatic controls which vent to the atmosphere when actuated	Replace natural gas with compressed air or electric controllers
Fugitive Emissions	There are numerous points along the value chain where methane can leak undetected	Install Leak Detection and Repair (LDAR) monitoring systems
Compressor Seals	Seals that prevent process gas from leaking between the rotating assembly in the stationary compressor case often fail	Centrifugal compressors - capturing methane emissions from the circulating seal oil converting to a dry seal configuration Reciprocating compressors - increasing rod packing replacement intervals
Engine Slip	Lean burn engines that reduce NO_x increase CH_4 emissions	Rich burn engines or electrification

Table 1: Methane Abatement Options

Similarly, there are opportunities to reduce carbon dioxide emissions across the natural gas value chain. The largest sources of CO_2 emissions are shown in Figure 7.

Figure 7: Sources of CO_2 emissions in the natural gas value chain



Source: Charting the Course: Reducing GHG Emissions from the U.S. Natural Gas Supply Chain – National Petroleum Council (April 2024)

There are also abatement options to reduce emissions from these sources (Table 2):

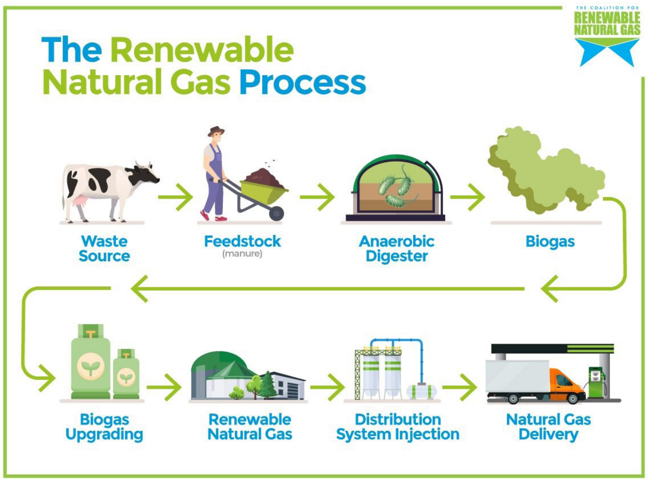
Key Source	Challenge	Abatement
Lease and Plant Fuel	CO_2 emissions from combustion of natural gas for compression, heating , and electricity generation	Electrification of compressors and heaters, purchase of low carbon electricity
Pipeline and Distribution Fuel	CO_2 emissions from combustion of natural gas for compression	Electrification of compressors, purchase of low carbon electricity
Flaring	CO_2 emissions from burning flared gas	Ensuring that sufficient lease takeaway capacity is available, improve operational reliability of key equipment

Table 2: CO_2 Abatement Options

Renewable Natural Gas

Non-fossil natural gas provides another avenue to lowering the carbon intensity of gas. The largest category of this low carbon non-fossil natural gas is bio-methane or renewable natural gas (RNG). RNG is a purified form of waste-derived biogas generated from anaerobic processes and then upgraded to pipeline-quality natural gas (Figure 8). Renewable natural gas is virtually indistinguishable from fossil natural gas and can be a "drop-in" replacement for fossil natural gas. There are more than 400 RNG facilities operating in North America.

Figure 8: The Renewable Natural Gas Process



Source: The Coalition for Renewable Natural Gas website

There are four major production pathways for renewable natural gas, based on four different waste feedstocks[9]:

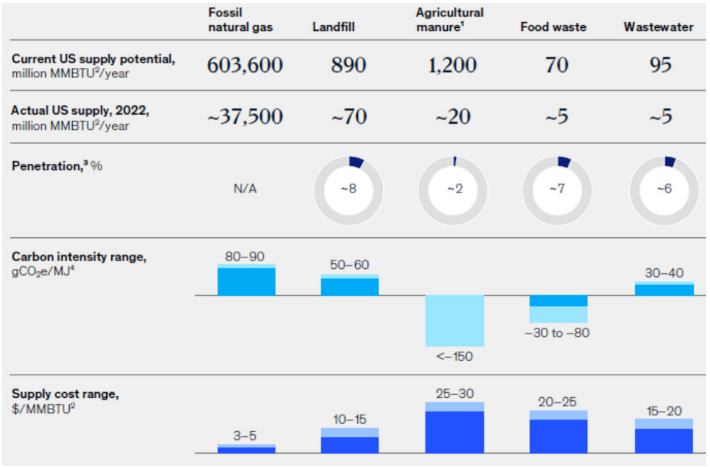
Landfill waste – Biogas captured from landfill waste is the cheapest source, as landfills are already required to capture the biogas, and this option requires only upgrading equipment. Landfill gas represents 70% of all RNG feedstock in the U.S. today.

Agricultural manure – Manure from dairy cattle, swine, and chickens converted to biogas and upgraded to RNG is the second largest source, representing about 20% of supply.

Food waste – Separated organic wastes can be converted to biogas and upgraded to RNG, although the low availability of separated organic wastes has limited it to 5% of U.S. RNG.

Wastewater treatment – Organic residues can be converted to RNG; this pathway is currently limited to 5% of U.S. RNG.

Figure 9: Characteristics of Main RNG Production Pathways



Source: Renewable natural gas: A Swiss army knife for U.S. decarbonization? – McKinsey (November 2023)

RNG currently represents less than 1% of natural gas production, and its long-term potential is limited by the availability of feedstock, even assuming 50%-70% of all available feedstock is processed (Table 3):

Feedstock	Low Resource Potential (Trillion BTU/YR)	High Resource Potential (Trillion BTU/YR)
Landfill Gas	528	866
Animal Manure	231	462
Waste Water Treatment	24	34
Food Waste	29	64
Total RNG Potential	812	1425
2023 US Gas Production	39246	39246
2040 RNG as % of 2023 US Gas Production	2%	4%

Table 3: 2040 U.S. RNG Potential[10]. Source: Renewable Sources of Natural Gas – American Gas Foundation (December 2019)

The growth of RNG production to date, while limited, has been driven by government incentives. The two main programs in the U.S. are the California Low Carbon Fuel Standard (LCFS) and investment tax credits in the 2022 federal Inflation Reduction Act (IRA). The LCFS provides incentives for lower carbon intensity transportation fuels. In the case of natural gas, this covers low carbon gas, which is sold as compressed natural gas (CNG). The LCFS book-and-claim system means developers do not have to physically deliver RNG to the end consumer, but rather "book" every unit of gas injected into the grid and "claim" consumption when the end user consumes a unit of gas. This means any RNG developer with access to a North American pipeline might sell to a CNG fleet in California and earn LCFS credit value. Unfortunately, current CNG markets are at risk of saturation because growth in U.S. demand for CNG is projected to slow after 2030 as improvements in electric vehicle battery technology result in electrification outcompeting CNG in medium-duty and heavy-duty fleets[11].

Potentially more important for the future is the 30% investment tax credit in the IRA for any "qualified biogas property system" that converts biomass to gas containing at least 52% methane for sale or productive use. "Qualified property" includes any on-site parts of a system that clean or condition the gas. It also includes later project modifications or expansions. In addition, the 30% investment tax credit will increase by 10% for projects that incorporate sufficient domestic content, and another 10% if they locate on brownfields or in "energy communities" with fossil electric plant retirements, coal mine closures, or high unemployment rates[12].

These credits are critical to RNG development. Today these projects are essentially greenhouse gas reduction projects, as the credits under the LCFS system, for example, account for about 95% percent of project revenue, compared to 5% from the value of the gas.

Initial investments in RNG have focused on the largest waste sources. Capturing a higher share of potential volumes will require construction of smaller digesters to access smaller waste sources, likely in clusters connected to central upgrading facilities.

Synthetic Methane

Synthetic methane is another option for lower carbon intensity natural gas. Also known as synthetic methane or e-methane, it is produced from captured CO_2 and low carbon hydrogen via the catalytic Sabatier reaction:

$$CO_2 + 4H_2 \dashrightarrow CH4 + 2H_2O$$

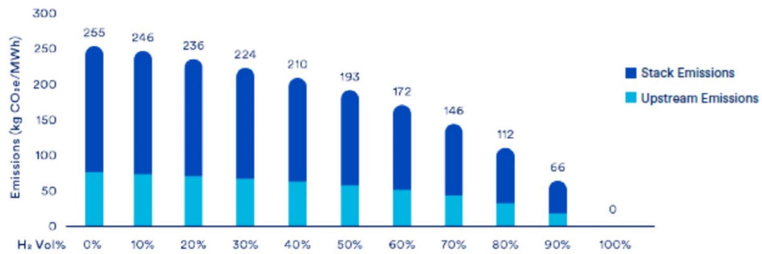
The life cycle emissions and production costs of synthetic methane depend primarily on the source of the captured CO_2, with high purity sources (ethanol, ammonia, and natural gas processing plants) resulting in lowest emissions and costs. Using a benchmark of 66 kilograms of CO_2 emissions per metric million British thermal units (MMBTU) for U.S. fossil natural gas (gas production plus transportation plus combustion emissions), CO_2 emissions from synthetic natural gas produced from high purity sources can be as low as eight or nine kilograms per MMBTU, or up to more than 30 kilograms for systems using energy intensive direct air capture technologies.

Current life cycle costs of synthetic natural gas (assuming $0.07/KWH electricity and $4/kg hydrogen) are estimated to be $45-$50/MMBTU, or 10 times current prices for fossil gas. However, synthetic natural gas production in the United States can attract the IRA's 45V tax credits for hydrogen production, which would reduce costs to $25-30/MMBTU[13], provided the hydrogen meets the three pillars of "additionality, hourly and geographical correlations" stipulated by U.S. Treasury rules issued in December 2023. Given the cost reductions required, this has a difficult path to being economic.

Hydrogen – Natural Gas Blends

A final option for producing lower emission natural gas is blending with low carbon hydrogen. Steam methane reforming enables the least expensive low carbon intensity hydrogen generation. Even lower intensity hydrogen can be created by splitting water to produce hydrogen and oxygen. In either case, the hydrogen can be blended into existing natural gas systems. The life cycle emissions of different hydrogen blending are shown in Figure 10.

Figure 10: Life Cycle Emissions for Hydrogen and Natural Gas Mixtures



Source: Hydrogen Blending: Not a serious decarbonixation pathway - Clean Air Task Force (May 2024)

However, there are serious challenges to blending significant volumes of hydrogen in natural gas systems. These include material degradation, operational requirements, and leakage. The limit for most existing systems is less than 10% of total volume. The only natural gas system currently incorporating significant hydrogen content is Hawaii Gas on Oahu, Hawaii. The system uses synthetic gas produced from naphtha blending with renewable natural gas and LNG, which typically contains about 15% hydrogen. The island's distribution system was built to handle manufactured gas or "town gas" (a mixture of hydrogen, carbon monoxide, and methane), which had much higher hydrogen levels[14].

Building Demand for Low Carbon Intensity Natural Gas

Global demand for low carbon intensity energy is expected to grow even in a business-as-usual scenario. In the International Energy Agency's State Policies Scenario, the share of renewable energy, nuclear, and natural gas grows from 40% of energy supply in 2022 to 58% of energy supply in 2050, displacing oil, coal, and traditional biomass[15]. For natural gas alone, global demand is expected to grow through 2030 in almost all scenarios[16]. In the Oxford Institute of Energy Studies Declared Policies Scenario, gas demand peaks in 2040 and declines slightly to 2050. Demand growth is strongest in developing countries in Asia and the Middle East, while demand declines in all developed regions. Production growth is expected to be focused in North America, the Middle East, and China (Table 4).

Demand			Annual Growth (%)	Share (%)
	2022	2040	2022-2040	2040
North America	1131	1119	*-0.1%*	23.7%
Middle East	590	807	*1.8%*	17.1%
China	367	564	*2.4%*	11.9%
Russia	512	507	*-0.1%*	10.7%
Europe	493	425	*-0.8%*	9.0%
ASEAN	158	240	*2.3%*	5.1%
South Asia	134	191	*2.0%*	4.0%
Central & South America	146	189	*1.4%*	4.0%
Japan, Korea, Taiwan	191	183	*-0.2%*	3.9%
North Africa	122	170	*1.9%*	3.6%
Others	404	333	*-1.1%*	7.0%
Total	4,248	4,728	*0.6%*	100.0%

Supply			Annual Growth (%)	Share (%)
	2022	2040	2022-2040	2040
North America	1275	1378	0.4%	29.1%
Middle East	728	1040	2.0%	22.0%
Russia	700	715	0.1%	15.1%
China	230	333	2.1%	7.0%
Caspian	202	192	-0.3%	4.1%
Sub-Saharan Africa	70	187	5.6%	4.0%
Central & South America	153	180	0.9%	3.8%
Europe	217	170	-1.3%	3.6%
North Africa	181	166	-0.5%	3.5%
Oceania	181	134	-1.7%	2.8%
Others	311	233	*-1.6%*	4.9%
Total	4,248	4,728	*0.6%*	100.0%

Table 4: Global Gas Supply Demand. Source: Oxford Institute of Energy Studies – IES Energy Transition Scenarios: Impact on Natural Gas (June 2024) – Declared Policies Scenario

International trade in natural gas will shift increasingly from pipeline gas to LNG. LNG's share of international gas trade is expected to grow from 63% today to 72% in 2040. (Table 5)

LNG Imports			Annual Growth (%)	Share (%)
	2022	2040	2022-2040	2040
Europe	168	193	*0.8%*	25.6%
Japan, Korea, Taiwan	185	182	*-0.1%*	24.1%
ASEAN	26	141	*9.8%*	18.7%
South Asia	42	95	*4.6%*	12.6%
China	89	88	*-0.1%*	11.7%
Others	26	56	*4.4%*	7.4%
Total	536	755	*1.9%*	100.0%
Top Five	510	699	*1.8%*	92.6%

LNG Exports			Annual Growth (%)	Share (%)
	2022	2040	2022-2040	2040
North America	104	266	*5.4%*	35.2%
Middle East	130	215	*2.8%*	28.5%
Sub Saharah Africa	33	87	*5.5%*	11.5%
Oceania	117	82	*-2.0%*	10.9%
Russia	44	67	*2.4%*	8.9%
Others	108	38	*-5.6%*	5.0%
Total	536	755	*1.9%*	100.0%
Top Five	428	717	*2.9%*	95.0%

Table 5: Global LNG Trade (BCM). Source: Oxford Institute of Energy Studies – IES Energy Transition Scenarios: Impact on Natural Gas (June 2024) – Declared Policies Scenario

Global pipeline gas trade will remain flat in aggregate, with Russian exports essentially redirected from Europe to China[17].

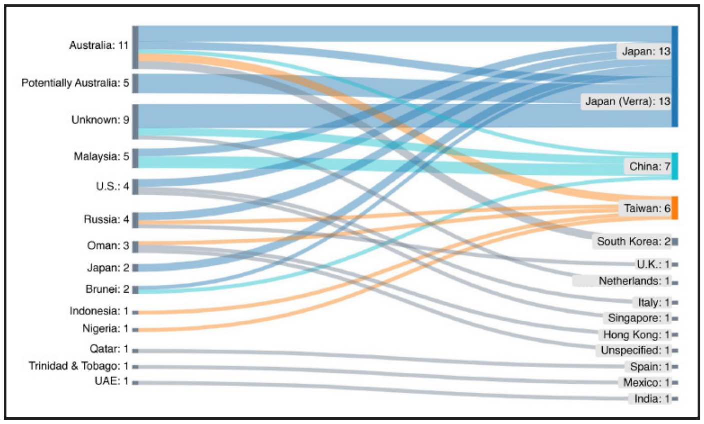
Global LNG trade will remain highly concentrated on a regional basis. LNG import growth will be highest in Southeast Asia and South Asia with demand flat in today's three largest markets (Japan/Korea/Taiwan, Europe, and China). The growth in demand will be met by LNG capacity expansion in North America, the Middle East, and Sub-Saharan Africa[18].

The current market for low intensity natural gas is small. However, three trends suggest it will grow. First, many gas and LNG producers have shown interest in reducing associated emissions and creating differentiation. Members of the industry's Oil and Gas Climate Initiative set a 0.2% methane intensity target, and the U.S. Inflation Reduction Act used this threshold as a baseline for its methane emission fee for oil and gas producers[19].

Second, some consumers already are expressing a preference for lower carbon intensity gas[20]. In 2019, a new phenomenon – so-called "carbon-neutral LNG" – was introduced into gas markets. It originated from two shipments delivered by Shell in June 2019 to the Japanese utility Tokyo Gas and a Korean energy company, GS Energy. The only difference from common deliveries of LNG was that the emissions of the supplied shipments were compensated with carbon offsets from nature-based projects.

The market soon expanded, with more shipments delivered by various companies to importers in India, Taiwan, Spain, and other countries (Figure 11).

Figure 11: Flow of Carbon Neutral LNG 2019 to the end of February 2023



Source: Carbon-Neutral LNG in Japan: Drivers and Perspectives - King Abdullah Petroleum Studies and Research Center (Aug 2023)

Finally, some governments are considering a tax on the carbon emissions of imported LNG. As this will increase gas prices in the internal markets where these taxes are imposed, some countries will likely be more amenable to this in order to accelerate the shift to lower carbon gas, making it most likely to be adopted in the developed importing countries of Europe and potentially in Northeast Asia. However, buyers in emerging Asian markets will remain wary of higher LNG prices and reluctant to follow suit[21].

A bifurcated LNG market is a likely outcome, one for premium, low carbon intensity gas and one for traditional, higher emission commodity gas. These differentiated gas markets allow gas to be marketed and sold based on verified carbon intensity of the supply chain.

Biggest Challenges to Developing Differentiated Natural Gas Markets

There are several requirements that must be met for differentiated gas markets to grow[22].

Standardization
Standardized accounting does not exist for many industries, including how to define asset boundaries, methodologies, and processes involving multiple products. That said, standardization in some markets is being driven by regulators, as with the European Carbon Border Adjustment Mechanism (CBAM), and voluntary declaration standards, such as the LNG methodology developed in 2022 by the International Group of Liquefied Natural Gas Importers. There are additional sectoral approaches (i.e., steel and cement industries) underway.

Sell-side Declaration
Differentiated trade can be accelerated by widespread supply-side declarations, enabling objective benchmarking instead of generic descriptions such as “low carbon”. This can arise via voluntary declarations from producers, mandates in procurement processes, or by regulation. For instance, during the United Nations Climate Change Conference held in Dubai in late 2023, 50 companies representing over 40% of global oil production launched the Oil and Gas De-carbonization Charter, a key element of which is “increasing transparency, including enhancing measurement, monitoring, reporting, and independent verification of greenhouse gas emissions”.

Buy-side Incentives
Buy-side declarations can create baselines for competition, whether for capturing end-user premiums, attracting competitive finance pools, or enabling tax rebate incentives. There are already examples of voluntary approaches in sustainable finance, procurement pledges like the World Economic Forum’s First Movers Coalition, and low carbon consumer offerings, but acceleration will come from increased regulatory measures, such as CBAM and Scope 3 footprint disclosures.

Measurement vs. Estimation
The market will develop a preference for measured rather than estimated carbon intensity[23]. Measurement involves deploying technology such as sensors to calculate actual methane emissions. Measurement can be difficult and costly in some parts of the value chain, such as compressor stations, so estimates may remain necessary for some time.

Independent Certification
There is increasing demand for independent certification of emissions. Rapid growth in U.S. differentiated gas began in late 2021 and continues to accelerate with increasing demand from domestic utilities and industry, as well as European energy companies. Approximately 30% of U.S. natural gas has been assessed as “differentiated gas”[24]. There are several agencies and standards which have different criteria for qualifying and rating gas. (Table 6)

Company	Certification Program	Supply Chain Target	Scope of Emissions	Certification Eligibility
Equitable Origin	EO100	Entire Supply Chain	Scope 1, 2, 3	3 years
Project Canary	TrustWell	Entire Supply Chain	Scope 1, 2	1 year
MiQ	MiQ Standard	Entire Supply Chain	Scope 1	1 year

Table 6: Gas Certification Organizations. Source: A critical review of natural gas emissions certification in the United States – Garg et al, Environmental Letters, Feb 2023

Policies Impacting Development of Low Carbon Intensity Gas Markets

Several types of policies could be deployed to support development of low carbon intensity gas markets. They include pricing/taxation, subsidies (adoption, financing), regulation (bans, phase-outs, mandates, performance standards), and information (required disclosure/labeling)[25].

The most aggressive policies to support the use of low carbon intensity natural gas are being implemented in Europe. CO_2 emissions are already covered in the European Union through the EU Emissions Trading System (EU-ETS). This mechanism controls carbon dioxide emitted by end users of fossil fuels by setting a benchmark for carbon pricing. The European Union treats methane differently than other greenhouse gases, in part because it is difficult to quantify. It is currently preparing the final text of a methane reduction law with extra-territorial reach. This law provides (1) upon enactment the European Commission will begin collection of methane emissions data, primarily at the scale of producing geological basins; (2) in 2027, reports on importer monitoring, measurement, reporting, and verification (MMRV) will be required for new import contracts; and (3) by 2030, all contracts must report MMRV efforts equivalent to EU requirements and must meet a methane intensity to be set by the European Commission in a future act[26]. A future import tax on methane emissions may be implemented to add to the CO_2 emission price.

Renewable natural gas and synthetic methane will also receive support from the EU's Renewable Energy Directive, which requires the share of renewable energy in the final consumption of energy in transport to reach at least 14% by 2030, including a minimum share of 3.5% for advanced biofuels[27].

In the U.S., the Inflation Reduction Act authorized the Environmental Protection Agency (EPA) to implement the Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems to cut methane emissions. The EPA has proposed collecting an annual waste emissions charge on methane emissions from oil and natural gas facilities if they exceed levels specified in the IRA[28].

California in 2023 became the first state to introduce a low-methane natural gas leakage procurement standard with Senate Bill 781. The bill would require state agencies to prioritize strategies to reduce methane emissions, including emissions from natural gas imports to the state. The overriding goal is to encourage a shift to low-methane natural gas[29].

Another potential policy to boost the move to lower carbon natural gas at the state level would allow regulated utilities to recover the cost of differentiated gas adoption, waiving typical requirements to purchase lowest cost gas[30].

As of today, there have been no major initiatives to implement an emissions tax on gas imports into north Asia, potentially reflecting the drive to replace the use of coal, as well as concerns over security of the natural gas supply.

A key policy question is whether support for low carbon hydrogen would be more effective than support for RNG and synthetic methane.

Conclusions

As the lowest carbon intensity fossil fuel, natural gas demand is expected to grow until 2040 and decline only slightly in the following decade. Demand growth will be strongest in developing countries in Asia and the Middle East, while demand is expected to decline in all developed regions. Production growth will be focused in North America, the Middle East, and China.

International trade in natural gas increasingly will shift from pipeline gas to LNG. LNG's share of international gas trade is expected to grow from 63% today to 72% in 2040. Global pipeline gas trade will remain flat, with Russian exports essentially redirected from Europe to China.

CO_2 and methane emissions along the fossil natural gas supply chain (production through delivery) vary considerably, depending on the source. Fortunately, there are many options fossil gas producers can use to reduce both methane and CO_2 emissions, lessening their carbon intensity.

In addition, new non fossil sources of methane with lower carbon intensities are emerging. This includes renewable natural gas, synthetic methane, and hydrogen-natural gas blends. As a result, customers now can choose between different sources of natural gas with different carbon intensities.

The current market for low intensity natural gas is small, and fossil natural gas remains less expensive. However, three trends suggest the market will grow. First, many gas and LNG producers are showing interest in reducing emissions associated with their products and creating differentiation. Second, some consumers already are expressing a preference for lower carbon intensity gas. Finally, some governments are considering taxes on emissions across the natural gas supply chain. The European Union already has pricing on carbon when combusted. Both the European Union and the U.S. are designing taxes based on methane emissions.

As a result, differentiated gas is likely to become a larger part of the global gas market.

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