CH4ARTING THE CO2URSE

Reducing GHG Emissions from the U.S. Natural Gas Supply Chain

VOLUME II • REPORT CHAPTERS AND APPENDICES

National Petroleum Council • 2024

National Petroleum Council

An Oil and Natural Gas Advisory Committee to the Secretary of Energy

1625 K Street, N.W.
Washington, D.C. 20006-1656

Phone: (202) 393-6100
Fax: (202) 331-8539

April 23, 2024

The Honorable Jennifer M. Granholm
Secretary of Energy
Washington, D.C. 20585

Dear Madam Secretary:

In response to your April 22, 2022, request, the National Petroleum Council (Council) conducted a comprehensive study on options to reduce greenhouse gas (GHG) emissions along the U.S. natural gas supply chain (NGSC). As you noted in your request, U.S. produced natural gas is an abundant resource that plays an essential role in energy security. Its use has had a significant role in reducing U.S. carbon emissions over the last twenty years and provides reliable electric power generation to support renewable energy sources, aiding in further overall reduction of GHG emissions. Innovations such as the combination of horizontal drilling and hydraulic fracturing have increased the supply of natural gas, leading to a reduction in its price and an increase in its use over more emission-intensive fuels, making natural gas an affordable and lower-emitting energy source in the United States.

Understanding, quantifying, and tracking GHG emissions is an essential component of measuring our progress in meeting emissions reduction targets. The oil and natural gas industry, policymakers, regulators, and technology providers must work together to continue to deliver natural gas safely, efficiently, and with a reduced GHG emissions footprint. This study, *Charting the Course—Reducing Greenhouse Gas Emissions from the Natural Gas Supply Chain*, maps out pathways to achieve those common goals.

This study focuses on six primary areas: GHG emissions characterization; high-emitting segments identification; emissions detection and estimation options; life cycle emissions analysis; potential trade-offs; and approaches to reduce GHG emissions. The study covers the entire U.S. NGSC, excluding end-user emissions, and emphasizes the need for investments, infrastructure changes, and regulatory advancements to reduce emissions. To evaluate the potential for GHG emissions reductions, the Council examined three emission reduction pathways, including a future pathway defined as the Technology, Innovation, and Policy (TIP) Pathway, where wider adoption of policies and regulations, deeper voluntary actions, advanced detection and monitoring technology, and expanded market mechanisms are employed. With this TIP Pathway, methane emissions are estimated to decrease by 70 percent and carbon dioxide emissions decrease by 33 percent from the NGSC between 2020 and 2050.

The Council introduced three unique aspects to enhance the study's value. First, this study provides a dedicated, stand-alone societal considerations and impacts (SCI) discussion to evaluate and integrate community and societal considerations into GHG reduction efforts. Focus groups and associated polls were commissioned in six regions impacted by the NGSC to deepen understanding of community engagement concerns and best practices. The SCI effort underscores that, while developing and implementing GHG emissions reduction projects, activities, and policies; industry and government avoid or mitigate adverse impacts on communities, particularly the disadvantaged, while maximizing the effectiveness of community benefits that can flow from these actions. Second, workshops were held with "less capitalized operators" to better understand the challenges of implementing GHG emissions reductions projects across all company types and sizes. Third, the Council developed a streamlined life cycle assessment (LCA) model of the carbon intensity of natural gas along a specific supply chain. The

LCA tool will be available to a wide spectrum of policymakers, researchers, and industry companies to democratize and mainstream what otherwise can be a complex analysis.

To convert the study's findings into action, multiple recommendations are detailed in the study for multiple stakeholders. The recommendations fall into the following major themes:

- *Energy and Economic Security:* Leveraging consequential analysis and recognizing the low GHG intensity of U.S. produced natural gas and LNG through climate and energy diplomatic efforts. Harmonizing methane policy across federal and state governments through the White House Methane Task Force adopting policy that utilizes durable market mechanisms to drive economically efficient GHG emissions reductions.

- *Promote SCI Awareness:* Committing investments to address social, environmental, and public health impacts and benefits of NGSC projects and activities and pursuing research based on SCI best practices and community engagement.

- *Incorporate More Measurement in Emissions Management*: Incorporating advanced technology measurements into measurement, monitoring, reporting, and verification (MMRV) programs and leveraging this study for development of a common MMRV global framework.

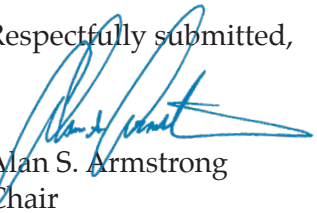
- *Technology Advancement to Further Emission Reductions:* Prioritizing research, development, demonstration, and deployment (RDD&D) of technologies for reducing and monitoring the GHG intensity of the NGSC.

- *Leverage Life Cycle Assessments (LCAs):* Leveraging LCAs to quantify supply-chain carbon intensities and develop measurement-informed geospatial LCA tools.

- *Employ Enablers for Change:* Revitalizing an organization like the Petroleum Technology Transfer Council for efficiently socializing best practices and technology adoption throughout industry.

In this study, the Council recommends actions that industry and government can undertake to maximize the value of our current infrastructure while further reducing GHG emissions from the NGSC and reducing the carbon intensity of natural gas to advance the United States toward meeting climate goals for the benefit of the public. The Council looks forward to sharing additional details with you, your colleagues, and broader government and public audiences about the pathways and prioritized options for reducing GHG emissions across the U.S. NGSC.

Respectfully submitted,



Alan S. Armstrong
Chair
National Petroleum Council

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Reducing GHG Emissions from the U.S. Natural Gas Supply Chain

VOLUME II • REPORT CHAPTERS AND APPENDICES

A Report of the National Petroleum Council
April 2024

Committee on GHG Emissions
Ryan M. Lance, Chair

NATIONAL PETROLEUM COUNCIL

Alan S. Armstrong, Chair
Ryan M. Lance, Vice Chair
Marshall W. Nichols, Executive Director

U.S. DEPARTMENT OF ENERGY

Jennifer M. Granholm, Secretary

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The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to oil and natural gas or to the oil and gas industries.

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The Report Summary, Chapters, Appendices, and other study materials can be downloaded at no charge from the NPC report website, chartingthecourse.npc.org.

Chapter 1

BASELINE EMISSIONS AND PATHWAYS

OVERVIEW

As stated in the request letter for this study,[1] "U.S.-produced natural gas is an abundant resource that plays an essential role in energy security. U.S.-produced natural gas can continue to provide reliable and affordable energy, both domestically and abroad, if its emissions are reduced and, ultimately, eliminated or offset by the asset owners and operators."

The Secretary of Energy asked the National Petroleum Council (NPC) to assess greenhouse gas (GHG) emissions reduction plans and potential throughout the natural gas supply chain, from extraction to distribution, through 2030 and 2050. Insights in this report should be valuable for not only the Department of Energy (DOE) and other government agencies and policymakers, but also for industry, technology innovators, commercial vendors, and standards-setting organizations.

This chapter contains five sections to provide background information on current GHG emissions and emerging regulations in the natural gas industry and to help illustrate baseline levels and future emissions reduction pathways associated with production, transmission, and delivery of natural gas in the United States.

Section I focuses on descriptions of the U.S. natural gas supply chain segments and the role of natural gas in the U.S. economy. The section also describes the U.S. GHG emissions reduction targets and the primary sources of GHG emissions within the natural gas supply chain.

Section II describes current and emerging policies at the state and federal level that aim to reduce GHG emissions within the natural gas industry and the role of voluntary programs and international initiatives within this ecosystem.

Section III introduces broader policy considerations around the role of U.S. natural gas in supporting energy affordability, reliability, and security both nationwide and with international allies.

Section IV outlines pathways for reducing GHG emissions levels within the natural gas supply chain in 2030 and 2050, including recommendations for areas that would support additional GHG reductions and how these levels support broader U.S. GHG commitments.

Section V summarizes key themes and conclusions from the work in this chapter.

I. ROLE OF U.S. NATURAL GAS

The United States is now the largest producer, consumer, and exporter of natural gas, and benefits from it as a resilient fuel source for industrial applications and electricity generation, including by providing reliable backup to support renewables, a feedstock for petrochemicals, a medium for seasonal energy storage, a source of natural-resource production royalties and taxes, and a valuable and strategically important energy source in global trade. Natural gas has a unique role in the U.S. economy and relationship with GHG emissions reduction targets. The increased

1 NPC. 2022. https://npc.org/files/GHG-Request_Letter_2022-04-22.pdf.

use of natural gas has been a main driver of GHG emissions reductions from the electric power sector by displacing coal-fired power generation. However, natural gas is also a source of GHG emissions from production, transport, and combustion. As reinforced by the U.S. commitment to the Global Methane Pledge, near-term reductions in methane emissions have become a GHG emissions reduction priority for both U.S. policymakers and the natural gas sector. Affordable, reliable, and lower carbon energy will be a pillar of success in any modern economy. All forms of energy have trade-offs or impacts, and this section will provide information regarding the role of natural gas in the U.S. economy, including the benefits and impacts.

A. Evolution of U.S. Greenhouse Gas Policy and Targets

Prior to the mid-2000s, the U.S. federal government principally addressed GHG emissions via voluntary programs such as Energy Star, AgStar, and the Environmental Protection Agency's (EPA) Center for Corporate Climate Leadership program. The mid-2000s introduced new congressional requirements for renewable electricity and fuels and a growth in tax incentives and federal grants supporting renewable energy generation, biomass fuels, and lower-emissions vehicles.

In 2007, Congress directed EPA to establish a GHG reporting program (GHGRP) to collect information about emissions levels from several industrial sectors. The establishment of the reporting program was not accompanied by policies requiring emissions reductions. In the same year, the Supreme Court found that EPA had the authority to regulate GHG emissions from motor vehicles under the Clean Air Act (CAA) in *Massachusetts v. EPA*. The decision required EPA to evaluate whether or not GHG emissions from new motor vehicles contribute to air pollution that may reasonably be anticipated to endanger public health or welfare.

EPA published such "endangerment findings" in 2009, referring to six GHGs (carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride). This finding triggered EPA obligations under the CAA to promulgate emissions standards for new motor vehicles and set off a cascade of regulations across other sectors, including direct regulation of GHGs from the electricity sector, the oil and gas industry, municipal solid waste landfills, and civilian aircraft.

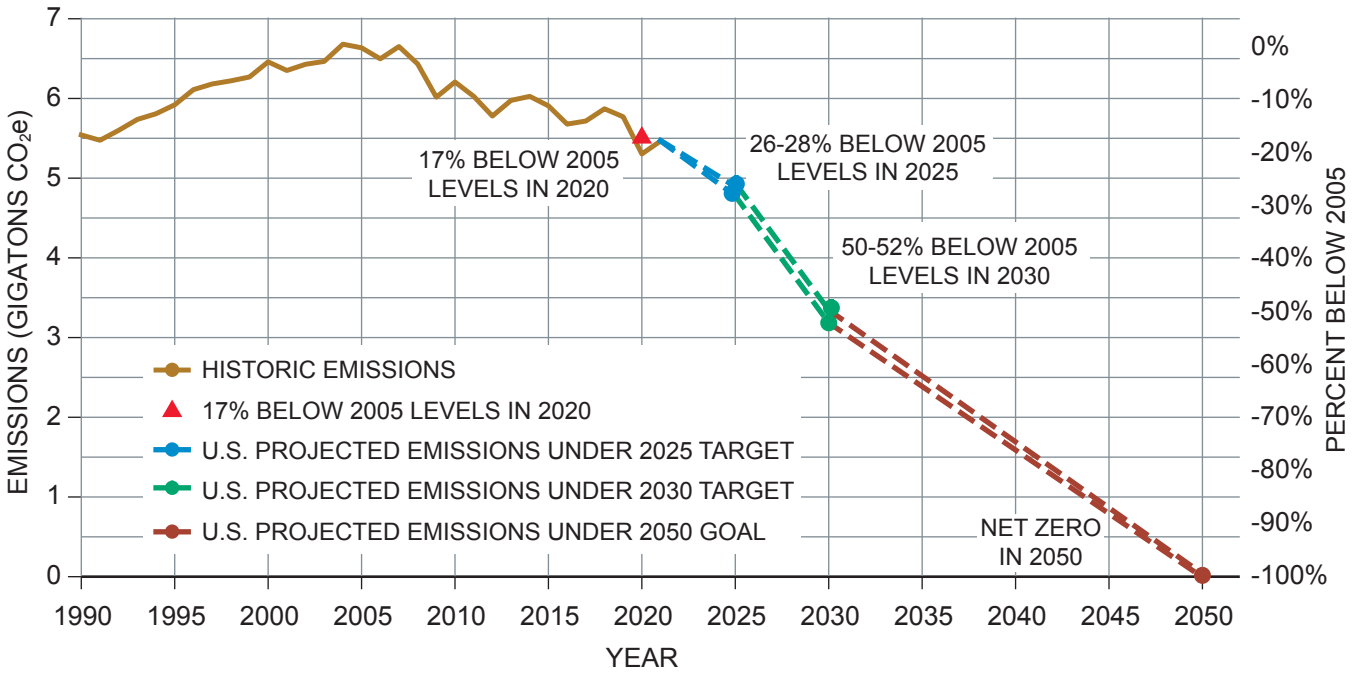
In 2021, the Biden administration issued several executive orders outlining its federal policy priorities with respect to climate issues. Two of the most notable provisions were rejoining the United Nations Framework Convention on Climate Change (UNFCCC) 2015 Paris Agreement and cosponsoring the Global Methane Pledge with the European Commission.

1. U.S. GHG Reduction Pledges

In 2015, the Paris Agreement[2] was reached by 196 countries that are parties to the UNFCCC at Conference of the Parties (COP) 21 in Paris. The Paris Agreement included a common global aim to hold the increase in the global average temperature to well below 2°C above preindustrial levels and pursue efforts to limit global temperature increase to 1.5°C above preindustrial levels. By executive action, the United States was among the original signatories to the agreement but withdrew in 2017. In 2021, the United States rejoined the Paris Agreement.

The Paris Agreement works on five-year cycles in which countries submit their nationally determined contributions (NDCs) to the UNFCCC. The NDCs lay out the short-term and long-term GHG reduction pledges for the country and include descriptions of the types of actions that will be undertaken to achieve those pledges. At the national level, reduction pledges can be unconditional or conditional, meaning they are contingent upon actions outside the control of the country like access to finance or certain types of GHG reduction technologies. The UNFCCC process includes country-level updates on progress against country-level pledges and continued negotiation of international implementation details of the Paris Agreement. The first global stocktake for progress against NDCs occurred at COP28 in 2023 in Dubai.

2 United Nations. 2015. "The Paris Agreement." United Nations Climate Change. https://unfccc.int/process-and-meetings/the-paris-agreement.



Source: U.S. State Department and Executive Offices of the President, 2021, "The Long-Term Strategy of the United States: Pathways to Net Zero Greenhouse Gas Emissions by 2050."

Figure 1-1. *U.S. Historic Emissions and Projected Emissions for 2030 and 2050 Targets*

As with other signatories to the Paris Agreement, the United States developed and submitted its NDC[3] to the UNFCCC process in 2021, which included the following economy-wide GHG reduction targets:

- 50%-52% reductions below 2005 levels by 2030, covering all sectors and all gases
- Net zero emissions no later than 2050

The U.S. NDC also includes examples of sector-specific policies that would underpin the 50%-52% economy-wide reduction target by 2030, including a goal for 100% carbon-free electricity generation by 2035, programs to increase efficiency in the transport, building, and industry sectors, and land management practices to increase natural carbon sequestration. For methane emissions, the U.S. NDC focused on reductions for oil and gas infrastructure and coal mines and incentive-based programs to reduce methane emissions from agriculture.

Figure 1-1 shows historic net GHG emissions in the United States and projections of a pathway developed by the U.S. government to 2030 and 2050 national targets. The agencies that developed these projections included a number of assumptions around near-term and long-term actions, including expanding technology deployment and investment pathways, 100% lower-carbon-intensity electricity by 2035, scaling support for related research, development, demonstration, commercialization, deployment of zero-carbon industrial innovations such as incentives for carbon capture and new sources of clean hydrogen, and the availability of natural and engineered carbon removal technologies as well.

Based on data for 2021,[4] U.S. net GHG emissions have decreased by ~17% relative to the 2005 baseline level. The pathway for GHG reduction outlined in Figure 1-1 relies on much steeper future rates of GHG reduction than the ~1% per year historic rate of reduction in the United

3 UNFCCC. 2021. "The United States of America Nationally Determined Contribution: Reducing Greenhouse Gases in the United States: A 2030 Emissions Target." https://unfccc.int/sites/default/files/NDC/2022-06/United%20States%20NDC%20April%2021%202021%20Final.pdf.

4 EPA. 2023. "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021." Table 2-8. https://www.epa.gov/system/files/documents/2023-04/US-GHG-Inventory-2023-Main-Text.pdf.

States. According to the Intergovernmental Panel on Climate Change (IPCC),[5] global GHG emissions continue to rise on an absolute basis, but emissions intensity has improved due to improvements in energy intensity of gross domestic product (GDP) and carbon intensity of energy. This can be largely attributed to the role natural gas has played in displacing coal since 2005.

2. Methane Emissions Reduction and the Global Methane Pledge

The United States and the European Union (with support from seven additional countries) announced an invitation to countries to support the Global Methane Pledge[6] at the September 2021 Major Economies Forum meeting. The Global Methane Pledge was then launched at COP26 the following November in Glasgow, where participants (including 24 new countries) agreed to take voluntary actions to reduce anthropogenic (human-caused) methane emissions by at least 30% from 2020 levels by 2030, to move toward using the highest-tier IPCC good practice inventory methodologies, and to continue improving the accuracy, transparency, consistency, comparability, and completeness of national GHG inventory reporting under the UNFCCC and the 2015 Paris Agreement. Since then, the Global Methane Pledge has grown to include 150+ participating countries and supporters, such as the Climate & Clean Air Coalition (CCAC) and U.N. Environment Programme (UNEP).

Methane accounts for ~17% of global GHG emissions,[7] and reduction efforts, like the Global Methane Pledge, have chosen to focus on methane emissions due to its short atmospheric lifetime and higher global warming potential, relative to carbon dioxide. Global warming potential is further explained in a later section of this chapter.

As part of its commitment to domestic methane emissions reduction, the White House released the U.S. Methane Emissions Reduction Action Plan[8] in November 2021, which discussed reduction efforts in specific economic sectors, including several regulatory actions within the natural gas industry:

- Updated EPA rules for methane from new oil and gas sources and its first set of guidelines to states for existing oil and gas sources
- Updated flaring and venting rules from the Bureau of Land Management (BLM) in the Department of the Interior (DOI) for operations on public lands
- Updated rules for methane calculation methodologies and implementation of the methane waste emissions charge from the Inflation Reduction Act.
- New rules from the Pipeline and Hazardous Materials Safety Administration (PHMSA)—part of the Department of Transportation (DOT)—that will, among other things, require operators to implement leak detection and repair programs

Several of these policy initiatives have become proposed or finalized regulations, which are discussed in depth in a later section on federal regulations.

In July 2023, the Biden administration announced the establishment of a new, cabinet-level White House Methane Task Force to accelerate execution of the U.S. Methane Emissions Reduction Action Plan, to coordinate the government's approach to methane leak detection and data transparency, and to support state and local efforts to implement and enforce methane emissions regulations. The administration's stated goal is that the Methane Task Force will strengthen interagency and multistakeholder action to dramatically reduce anthropogenic methane emissions.

Internationally, the Global Methane Pledge also included announcements of new funding and support programs to assist signatory countries in developing methane reduction plans and sharing best practices for methane reduction in the energy, waste, and agricultural sectors with

5 IPCC. 2022. "Mitigation of Climate Change Summary for Policymakers Climate Change 2022 Working Group III Contribution to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change." https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC_AR6_WGIII_SPM.pdf.

6 "Global Methane Pledge." November 22, 2023. https://www.globalmethanepledge.org/resources/global-methane-pledge.

7 "Global Methane Pledge." November 22, 2023. https://www.globalmethanepledge.org/resources/global-methane-pledge.

8 The White House Office of Domestic Climate Policy. "U.S. Methane Emissions Reduction Action Plan." November 2021. https://www.whitehouse.gov/wp-content/uploads/2021/11/US-Methane-Emissions-Reduction-Action-Plan-1.pdf.

the goal of increasing the number of countries that include specific methane emissions reduction actions with their next NDC submission to the UNFCCC.

B. The Role of the U.S. Natural Gas Industry

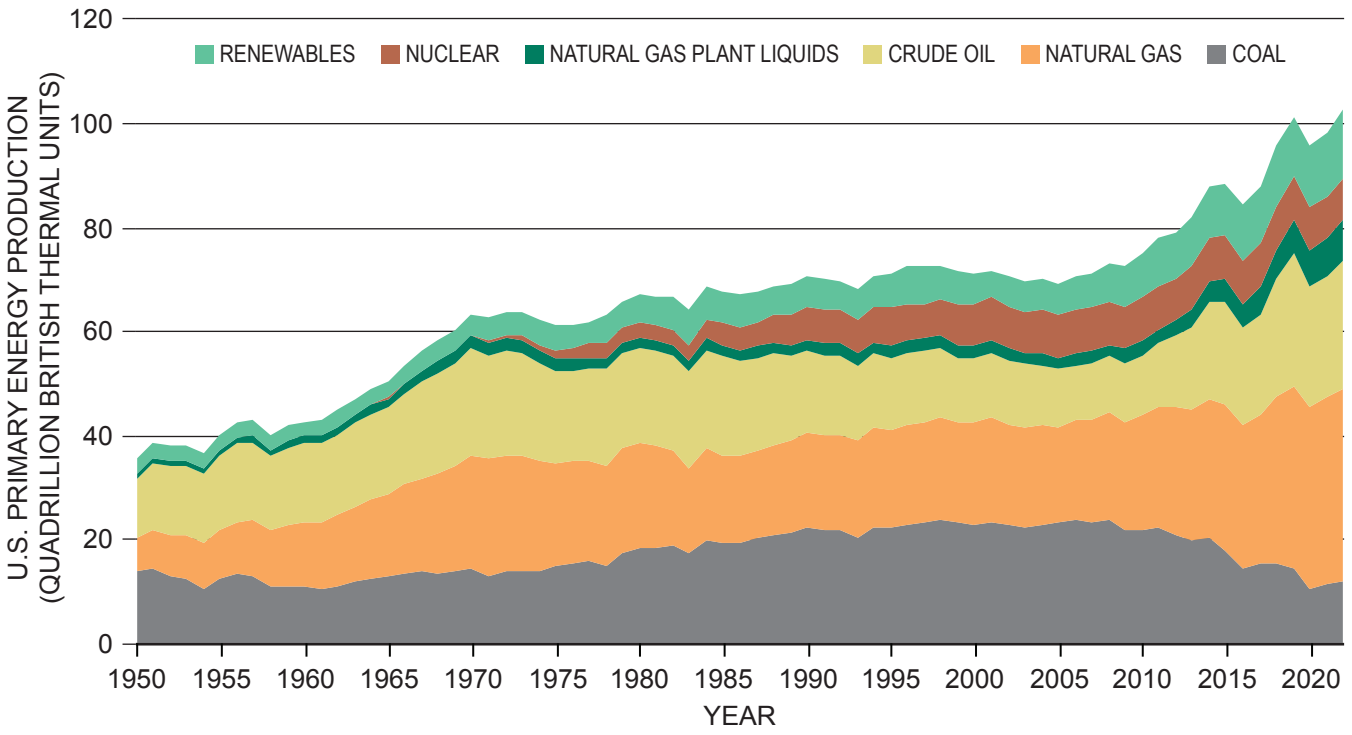
According to the American Public Gas Association,[9] gas produced from coal was first used to light street lights in Baltimore in 1816. The first natural gas well was drilled in 1821 in Fredonia, New York, which gave rise to the first natural gas distribution company: the Fredonia Gas Light Company. During the 19th century, natural gas was primarily used as a source of light but, with the invention of the Bunsen burner and the construction of more reliable distribution pipelines, the use of natural gas expanded to other applications. In the 20th century, natural gas began to be used in residential processes (e.g., cooking, home heating, appliances), manufacturing and processing plants, and in boilers to generate electricity, playing an increasingly important role in modern society and the country's economy. Natural gas continues to play this role today.

Energy Information Administration (EIA) data show that natural gas has been a growing part of the energy mix since 1950, as shown in Figure 1-2. This was due to improvements in metals, welding techniques, and pipe making that were developed and made during wartime. These events, in turn, made pipeline construction more economically feasible and led to thousands of miles of pipelines being constructed in the 1950s and 1960s.[10]

Around 2010, the deployment of innovative technologies, including horizontal drilling and hydraulic fracturing, allowed previously uneconomic sources of natural gas to be produced.

9 American Public Gas Association. "A Brief History of Natural Gas." n.d. Accessed December 11, 2021. https://www.apga.org/apgamainsite/aboutus/facts/history-of-natural-gas#:~:text=In%20the%20United%20States%2C%20the.

10 DOE. "Fossil Energy Study Guide: Natural Gas" n.d. https://www.energy.gov/sites/prod/files/2014/02/f8/HS_NatGas_Studyguide_draft2.pdf.



Source: EIA, April 2023, preliminary data for 2022, "Monthly Energy Review," Table 1.2.

Figure 1-2. *U.S. Primary Energy Production by Major Sources, 1950-2022*

This new supply of gas, often referred to as shale gas, had a major impact on price and supply. With lower prices and a reliable supply, the use of natural gas in many sectors increased, most notably in the electric power sector. Petroleum and natural gas are the largest sources of U.S. primary energy production, providing approximately 70% combined, as shown in Figure 1-2.

In industry, natural gas is used for process heating where high-temperature or efficient heat transfer is needed and has multiple applications. In the transportation sector, natural gas is used as fuel to operate compressors and as a vehicle fuel in the form of compressed natural gas and liquefied natural gas (LNG).

End-Use Sector	Percentage (%)
Electric Power	38
Industrial	32
Residential	15
Commercial	11
Transportation	4

Source: EIA, 2023, "Use of Natural Gas."

Table 1-1. *Natural Gas—End Use by Sector in 2022*

As will be discussed in detail in Section III, the oil and natural gas industry has provided sizable benefits to the U.S. economy,[11, 12] including domestic energy security, significant numbers of jobs, and support for the development of other industries like chemical and fertilizer production, where natural gas cost and availability have been key decision criteria for investment.

1. Energy Mix and Power Sector GHG Reductions

Natural gas supplies a third of overall U.S. energy consumption[13] and is used across the U.S. economy. In 2022, natural gas consumption was split among electric power (38%), industrial (32%), residential (15%), and commercial (11%) sectors. The commercial sector includes service-providing facilities and equipment of businesses, and common uses of energy associated with this sector include space heating, water heating, air conditioning, refrigeration, and cooking. It is important to note that a shift from direct use of natural gas in commercial or residential sectors to electrification will require better grid infrastructure and a continuous supply of electricity. In the last two decades, natural gas consumption[14] has increased by more than 55% to reach 32.3 trillion cubic feet (Tcf) in 2022. Through jobs and the energy supplied, the natural gas and oil industry supported $1.8 trillion of U.S. GDP (about $5,500 per person in the United States), around 7.6% of the national total.[15]

Combustion of natural gas produces less carbon dioxide (CO_2) per unit of energy than other fossil fuels such as coal and oil, but given natural gas is such a large share of the overall energy powering the economy, it accounts for a significant share of the U.S. GHG emissions, which will be discussed in depth in this chapter.

2. Trends in Domestic Production

The United States has seen significant increases in natural gas production since the mid-2000s as technology improvements in hydraulic fracturing and horizontal directional drilling unlocked gas production from shale formations and operational efficiency gains improved the economics of production. Shale gas is natural gas produced from a shale formation, and it can be associated gas from an oil well or it can be nonassociated gas from a natural gas well.

Domestic natural gas production involves a wide range of companies. As shown in Figure 1-3, the 10 largest natural gas producers by volume account for approximately one-third of U.S.

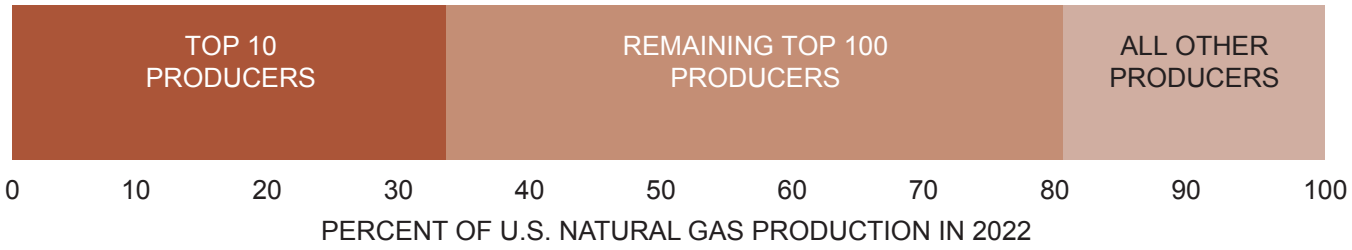
11 DOE. "U.S. Oil and Natural Gas: Providing Energy Security and Supporting Our Quality of Life." September 2020. https://www.energy.gov/sites/prod/files/2020/10/f79/Natural%20Gas%20Benefits%20Report.pdf.

12 NERA. "Updated Macroeconomic Impacts of LNG Exports from the United States." March 24, 2014. https://www.nera.com/insights/publications/2014/updated-macroeconomic-impacts-of-lng-exports-from-the-united-sta.html.

13 EIA. "Use of Natural Gas." May 26, 2021. https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php.

14 "U.S. Natural Gas Consumption by End Use." May 31, 3024. https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

15 API. "New Analysis: America's Abundant Natural Gas and Oil Resources Deliver Americans Nearly $2 Trillion in Economic, Trade, & Job Benefits." May 16, 2023. www.api.org. https://www.api.org/news-policy-and-issues/news/2023/05/15/abundant-natural-gas-oil-resources-deliver-americans-nearly-2-trillion-economic-trade-job-benefits#:~:text=Supported%20nearly%20%241.8%20trillion%20in.



Source: Rystad, 2023.

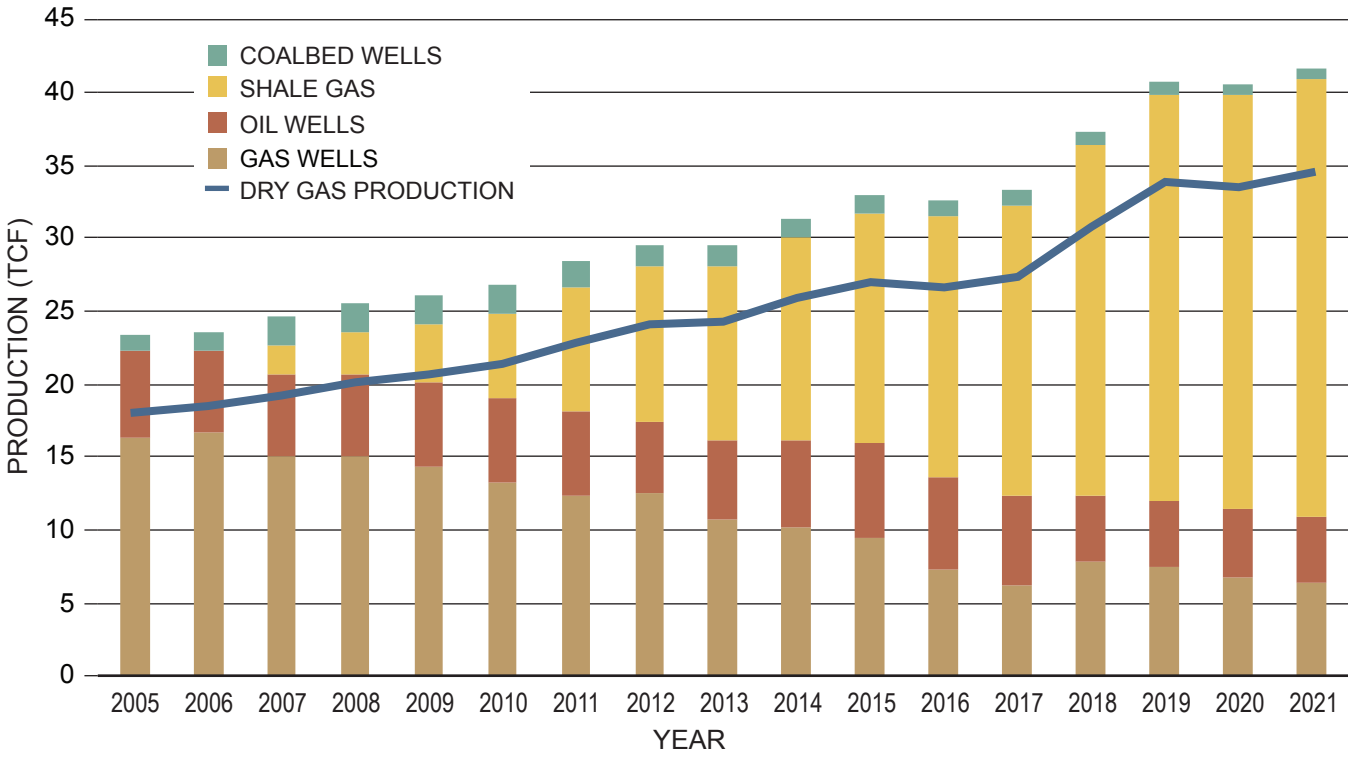
Figure 1-3. *Gross Natural Gas Production in the United States in 2022*

production, and more than 100 firms currently account for 80% of U.S. production. The remaining 20% of production is split among thousands of other producers. For reference, there are more than 1,600 active producers in Texas.[16]

With shale gas driving the growth in domestic gas production (72% of gross gas production in 2021), natural gas from conventional oil and gas wells has declined with natural gas production from offshore wells dropping from 5.8 Tcf in 2001 to 1.3 Tcf in 2021 (Figure 1-4).[17] Shale gas production comes from both nonassociated gas production in the Marcellus (Appalachia) and Haynesville (East Texas/Arkla) basins and associated gas production in places like the Permian Basin (Figure 1-5). Five states accounted for 70% of 2021 U.S. dry gas (also known as consumer-grade natural gas) production: Texas (24.6%), Pennsylvania

16 "Texas Oil and Gas Producers by Rank." 2021. https://www.rrc.texas.gov/oil-and-gas/research-and-statistics/operator-information/texas-oil-and-gas-producers-by-rank-2021/.

17 EIA. "U.S. Natural Gas Gross Withdrawals and Production." May 31, 2024. https://www.eia.gov/dnav/ng/ng_prod_sum_dc_nus_mmcf_a.htm.



Source: EIA, 2024, "US Natural Gas Gross Withdrawals and Production."

Figure 1-4. *U.S. Natural Gas Production by Well Type*

(21.8%), Louisiana (9.9%), West Virginia (7.4%), and Oklahoma (6.7%).[18]

Figure 1-6 shows different sources of natural gas. Associated gas production in the United States grew significantly from 2010 to 2019, because of increased crude oil production from tight rock formations e.g., Permian, Eagle Ford, Bakken, Niobrara, and Anadarko basins. The Permian Basin accounts for 50% of the associated gas production in the United States, and associated gas production accounts for about 12.5% of total U.S. natural gas production.[19] Associated gas began to decline in 2020 for the first time since 2016.[20] However, production of associated gas is predicted to grow through 2050 in EIA's *Annual Energy Outlook 2023* (AEO2023) analysis, which is published annually and explores the long-term energy trends in the United States. To illustrate the role of uncertainty, AEO2023 includes a baseline reference case and several side cases that vary important underlying assumptions.[21]

FINDING 1: Development of unconventional natural gas fields has transformed the United States energy system. Natural gas overtook coal as the largest source of U.S. primary energy production after 2010.

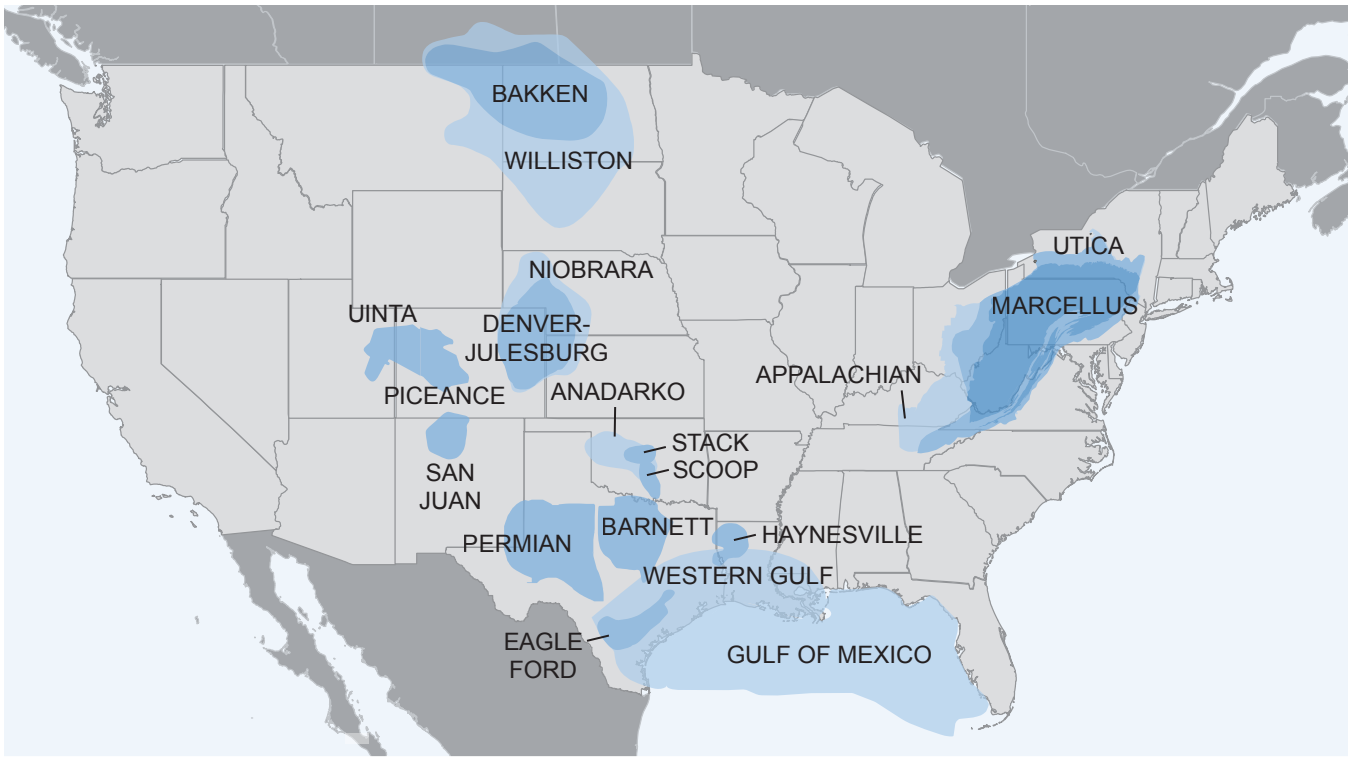
FINDING 2: Since 2005, U.S. natural gas production has nearly doubled and transformed from a system based on conventional resources to one primarily driven by shale resource development. In 2021, more than 70% of U.S. production was from shale resources.

18 EIA. 2016. "Where Our Natural Gas Comes From." https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php.

19 EIA. "Associated Natural Gas Production Declines in 2020, Following Three Years of Growth." August 23, 2021. https://www.eia.gov/todayinenergy/detail.php?id=49256.

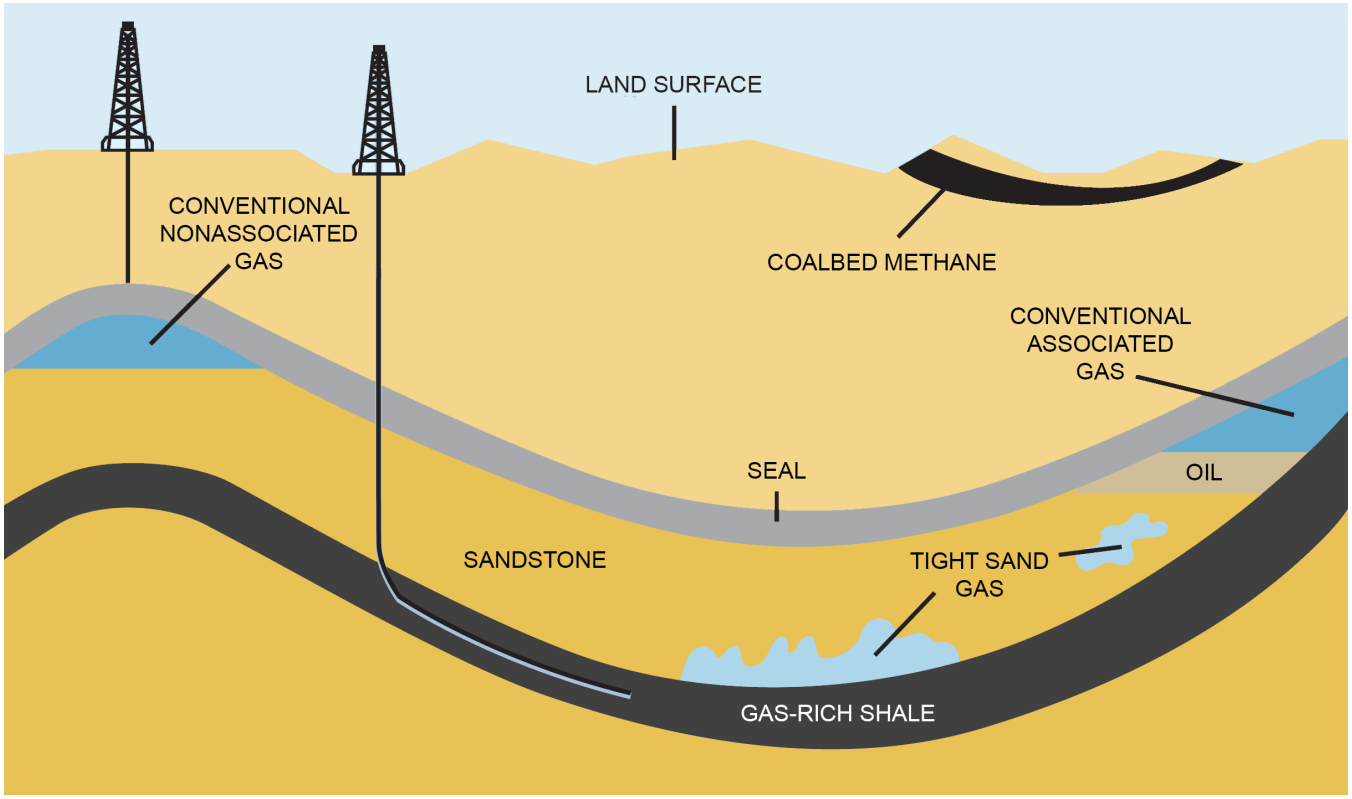
20 EIA. "Associated Natural Gas Production Declines in 2020, Following Three Years of Growth." August 23, 2021. https://www.eia.gov/todayinenergy/detail.php?id=49256.

21 EIA. "U.S. Associated Natural Gas Production Will Likely Grow through 2050 in Our AEO2023." April 11, 2023. https://www.eia.gov/todayinenergy/detail.php?id=56120.



Source: RBN Energy LLC.

Figure 1-5. *Basins That Account for Majority of U.S. Natural Gas Production*



Source: EIA, 2011, "The Geology of Natural Gas," https://www.eia.gov/todayinenergy/detail.php?id=110.

Figure 1-6. *The Geology of Natural Gas Resources*

3. U.S. LNG Exports

The United States has been a commercial exporter of LNG since 1969[22] when the Kenai LNG plant in Alaska began exports and in the Lower 48 states since 2016 when the Sabine Pass terminal in Louisiana began operations.[23] During the past decade, the United States has transformed from a net importer of LNG to a net exporter. In 2016, the United States exported an average of 0.5 billion cubic feet per day (Bcf/d)[24] and since then, LNG exports have grown rapidly with the United States becoming the largest LNG exporter in the world during the first half of 2022, achieving export volumes of 11.2 Bcf/d.[25] In 2022, the United States accounted for 18% of global LNG volumes.[26] Most of the currently operating and approved U.S. LNG export capacity is located along the U.S. Gulf Coast.

As of April 2023, there were seven U.S. export terminals in operation: Sabine Pass, Cameron, Freeport, Elba Island, Cove Point, Corpus Christi, and Calcasieu Pass that exported an average of 10.6 bcf/d in 2022 (Figure 1-7). There are three additional LNG export terminals under construction; Golden Pass LNG (2.4 Bcf/d), Plaquemines LNG (1.8 Bcf/d), and Corpus Christi Stage III (1.6 Bcf/d) that, if completed on schedule, will expand peak export capacity by 5.7 Bcf/d to total 19.7 Bcf/d by 2025.

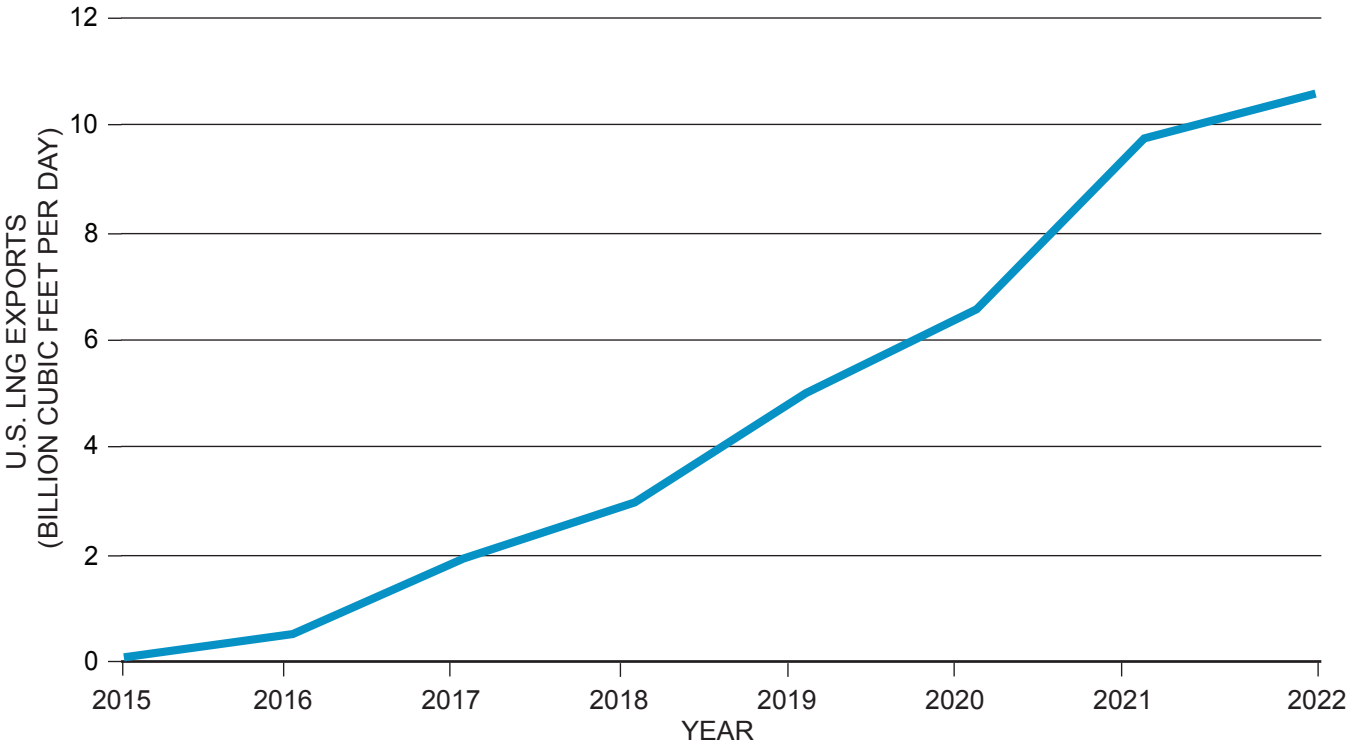
22 ConocoPhillips. n.d. "Our History – Kenai Peninsula/Cook Inlet." https://alaska.conocophillips.com/who-we-are/our-history/#:~:text=On%20June%208%2C%201969%2C%20production,of%20the%20Kenai%20LNG%20Facility.

23 "Sabine Pass." n.d. Cheniere. https://www.cheniere.com/where-we-work/sabine-pass.

24 EIA. "Liquefied U.S. Natural Gas Exports (Million Cubic Feet)." May 31, 2024. https://www.eia.gov/dnav/ng/hist/n9133us2A.htm.

25 EIA. "The United States Became the World's Largest LNG Exporter in the First Half of 2022." July 25, 2022. https://www.eia.gov/todayinenergy/detail.php?id=53159.

26 "The LNG Industry GIIGNL Annual Report 2022." 2022. https://giignl.org/wp-content/uploads/2022/05/GIIGNL2022_Annual_Report_May24.pdf.



Source: EIA, 2024, "Liquefied U.S. Natural Gas Exports."

Figure 1-7. *U.S. LNG Export Volumes*

The United States has exported LNG to more than 40 countries since 2016.[27] Most U.S. exports to date have gone to South Korea, China, Japan, and Brazil.[28] However, since the February 2022 invasion of Ukraine by Russia, more than 60% of U.S. LNG exports have been delivered to Europe.[29] Export contracts from the United States have often not had a destination clause (i.e., a clause that designates a list of unloading terminals as destination ports of LNG ships and prevents buyers from reselling LNG to other markets). This allows for U.S. volumes to rapidly respond to demand signals, which will be discussed in detail later in this chapter.

FINDING 3: The United States is now the largest producer, consumer, and exporter of natural gas.

4. Pipeline Imports and Exports

The United States also imports and exports natural gas to Mexico and Canada via pipeline (Figure 1-8). In 2022, the United States imported approximately 8% of its total natural gas supply from Canada, although this has declined considerably in the past 20 years due to increased domestic production. Imports arrive principally through border crossing points in Washington at the Enbridge BC Pipeline (1.6 Bcf/d capacity) and the Kingsgate Pipeline (2.9 Bcf/d capacity), and Idaho through the Monchy (2.2 Bcf/d) and Alliance Pipeline (1.6 Bcf/d) to meet winter heating-demands in the Pacific Northwest, California, and the American Midwest.[30] U.S. natural gas exports to Canada have remained relatively flat over the last decade, delivering primarily to the Northeast regions.

27 EIA. "U.S. Natural Gas Exports by Country." May 31, 2024. https://www.eia.gov/dnav/ng/ng_move_expc_sl_a.htm.

28 EIA. "U.S. Natural Gas Exports by Country." May 31, 2024. https://www.eia.gov/dnav/ng/ng_move_expc_sl_a.htm.

29 EIA. "Natural Gas Weekly Update." January 11, 2023. https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2023/01_12/.

30 Government of Canada, Canada Energy Regulator. 2022. "NEB–Natural Gas Pipeline Transportation System." April 11, 2022. https://www.cer-rec.gc.ca/en/data-analysis/facilities-we-regulate/canadas-pipeline-system/2021/natural-gas-pipeline-transportation-system.html.

Exports of gas to Mexico, however, have increased more than 600%[31] as a result of new pipeline infrastructure from Texas into Mexico near the Permian Basin and increased demand for imported gas due to declining Mexican domestic natural gas production.[32] Two cross-border pipelines have driven the growth in exports since 2020; the Sur de Texas-Tuxpan Pipeline (2.6 Bcf/d capacity) and the Trans-Pecos Pipeline (1.4 Bcf/d capacity).[33] U.S. natural gas exports to Mexico reached 6.1 Bcf/d in 2023.[34]

5. Domestic Gas Storage

The United States has 4.8 Tcf of working natural gas underground storage capacity across 412 active facilities, including depleted reservoirs in oil and/or natural gas fields, aquifers, and salt cavern formations (Figure 1-9).[35] This represents approximately 15% of annual domestic consumption.[36] Most existing storage capacity in the United States is in depleted oil and gas fields close to consumption centers and is designed to balance supply and demand during off-peak and peak demand periods. When integrated with the vast U.S. pipeline network, this reinforcement adds resilience and facilitates reliable transportation of natural gas across the country to meet local demand and provide high deliverability to end users.[37]

Specifically, gas storage is used to provide natural gas supplies to meet peak demands of the winter heating season and for a growing, year-

31 EIA. "U.S. Natural Gas Pipeline Exports by Point of Exit." May 31, 2024. https://www.eia.gov/dnav/ng/ng_move_poe2_a_EPG0_ENP_Mmcf_a.htm.

32 EIA. "U.S. Natural Gas Exports to Mexico Established a New Monthly Record in June 2021." July 23, 2021. https://www.eia.gov/todayinenergy/detail.php?id=48836.

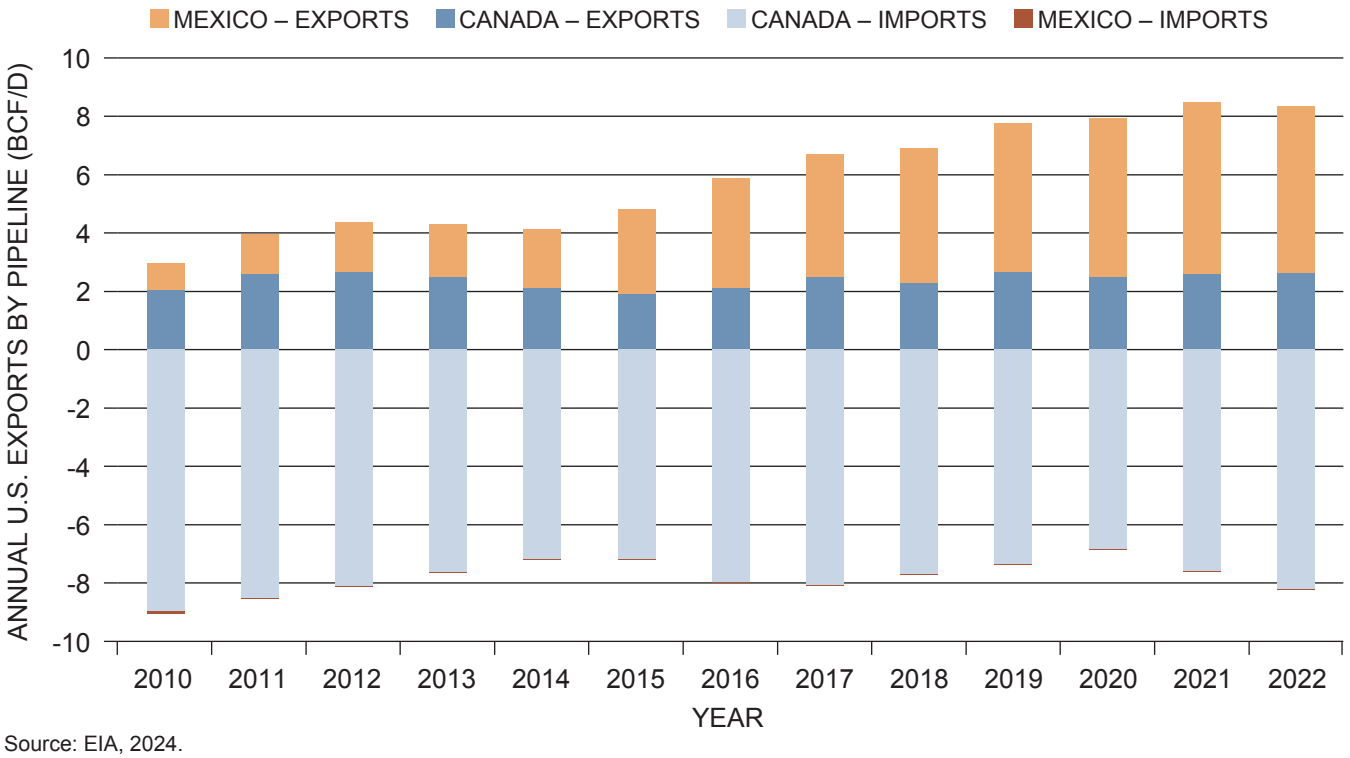
33 EIA. "U.S. Natural Gas Exports to Mexico Established a New Monthly Record in June 2021." July 23, 2021. https://www.eia.gov/todayinenergy/detail.php?id=48836.

34 EIA. "U.S. Natural Gas Pipeline Exports by Point of Exit." May 31, 2024. https://www.eia.gov/dnav/ng/ng_move_poe2_a_EPG0_ENP_Mmcf_a.htm.

35 EIA. "U.S. Underground Natural Gas Storage Capacity." May 31, 2024. https://www.eia.gov/dnav/ng/ng_stor_cap_dcu_nus_a.htm.

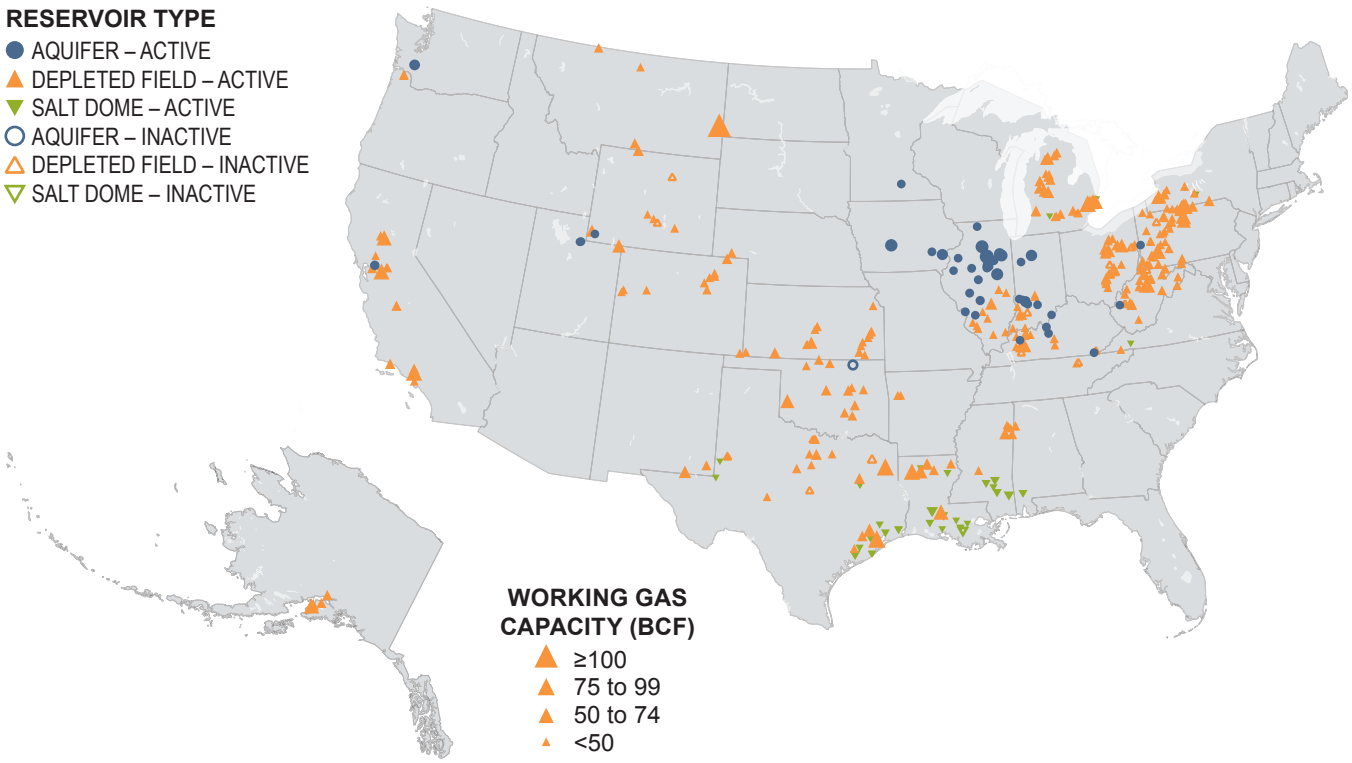
36 Congressional Research Service. "Natural Gas Markets Going Global: Changes in Consumption." November 23, 2022. https://crsreports.congress.gov/product/pdf/R/R47317.

37 EIA. "Underground Natural Gas Working Storage Capacity." 2016. https://www.eia.gov/naturalgas/storagecapacity/.



Source: EIA, 2024.

Figure 1-8. *U.S. Natural Gas Imports and Exports with Canada and Mexico*



Source: EIA, 2017.

Figure 1-9. *Location of U.S. Underground Natural Gas Storage Facilities*

round demand of electric power generation for winter heating and summer cooling. Seasonal periods of high demand or shorter-term periods during utility-scale emergencies can exceed available production and/or pipeline capacity, but storage provides the buffer to ensure uninterrupted supply, especially for residential customers. A secondary function is to allow for temporary balancing of mismatches between production, demand, and transportation. Examples might be cooler-than-normal summer days or warmer-than-normal winter days. Thus, underground natural gas storage provides necessary flexibility and resiliency for transportation and distribution.

FINDING 4: **Natural gas storage capacities are abundant and play a vital role in ensuring that supplies are available when needed and for a sustained period. The availability of a diverse set of storage options with large capacity is a key aspect of the U.S. natural gas chain.**

6. Revenue from Production and Exports

In 2021, the United States exported 18 Bcf/d from pipeline gas and LNG combined. Taking the average price for LNG exports in 2021 of $7.62/Mcf and pipeline exports of $4.94/Mcf[38] that equates to $27 billion from LNG exports and $15 billion from pipeline exports for a total value of $42 billion in 2021. The value from natural gas exports is considerably smaller than the $83.3 billion from refined petroleum exports in 2021 but still in the top 10 of overall U.S. exports. Export volumes were at record levels in 2022 and are expected to reach 25 Bcf/d by 2025 as new LNG export capacity and pipeline capacity come online. Revenue from natural gas exports may exceed $50 billion a year with continued growth within the next few years.

Recent trends in the growth of domestic natural gas consumption are projected in AEO2023 to flatten, with consumption remaining relatively

38 EIA. "U.S. Natural Gas Exports by Country." May 31, 2024. https://www.eia.gov/dnav/ng/ng_move_expc_sl_a.htm.

stable through 2050.[39] Despite the leveling off in domestic natural gas consumption, U.S. natural gas production is forecasted to increase across most scenarios in AEO2023, with an increase of 15% forecasted from 2022 to 2050 in its reference case. A significant driver of production growth is international LNG export demand with annual LNG exports growing to 27 Bcf/d in 2038 from 11 Bcf/d in 2022. The AEO2023 expects gas production to grow in areas that have better access to export terminals.

In AEO2023, future U.S. production growth is highly dependent on how much LNG export capacity and the pipelines needed to supply those terminals is built over the next 30 years. Export volumes could be a significant source of revenue as well as an important global power sector carbon reduction lever in some importing regions, similar to the way natural gas was for the U.S. power sector, as discussed in the next section.

7. Role in Power Sector Emissions Reductions

From 1975 to 2015, the electric power sector was the largest direct source of GHG emissions in the United States, with the sector's primary sources of GHG emissions coming from the combustion of coal, natural gas, and smaller amounts of petroleum products, like diesel. The power sector is now the second-largest source of GHG emissions after transportation.[40]

Coal-fired electricity generation in the United States grew more than 1,000% between 1950 and 2008 and was the largest source of electricity generation through 2015.[41] As coal-fired electricity has the highest rate of combustion-related emissions in the electricity sector,[42] carbon dioxide emissions from the electric power sector also increased until 2008.[43]

The Public Utility Regulatory Policies Act (PURPA) was developed in response to events following the energy crisis around 1973–1974 and was coupled with several other acts to address certain strategic energy concerns, such as capacity to switch fuels from natural gas back to coal in the event of an energy emergency in the Fuel Use Act of 1978. PURPA started the movement toward the Independent Power Producers industry and focused on cogeneration facility development. This and other policies resulted in the offsetting of coal as a primary fuel in electric generation and the notable reductions in criteria pollutants and GHG.

Between 2000 and 2005, 192 GW of natural gas-fired electricity generation capacity were added to the U.S. electric grid (Figure 1-10), which was the fastest buildout of electricity capacity in the history of the country.[44]

This high natural gas generation capacity was coupled with an additional trend: developing tight oil and shale gas resources, which was discussed earlier in this chapter. Research and development between the 1970s and 1990s led to improved seismic imaging, sturdier diamond-headed drill bits, and horizontal drilling and hydraulic fracturing techniques.[45] The combination of these techniques greatly expanded the

39 EIA. "Annual Energy Outlook 2023." March 16, 2023. https://www.eia.gov/outlooks/aeo/narrative/index.php#InternationalDemandfor.pdf.

40 EPA. "Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2020." https://www.epa.gov/system/files/documents/2022-04/us-ghg-inventory-2022-chapter-3-energy.pdf.

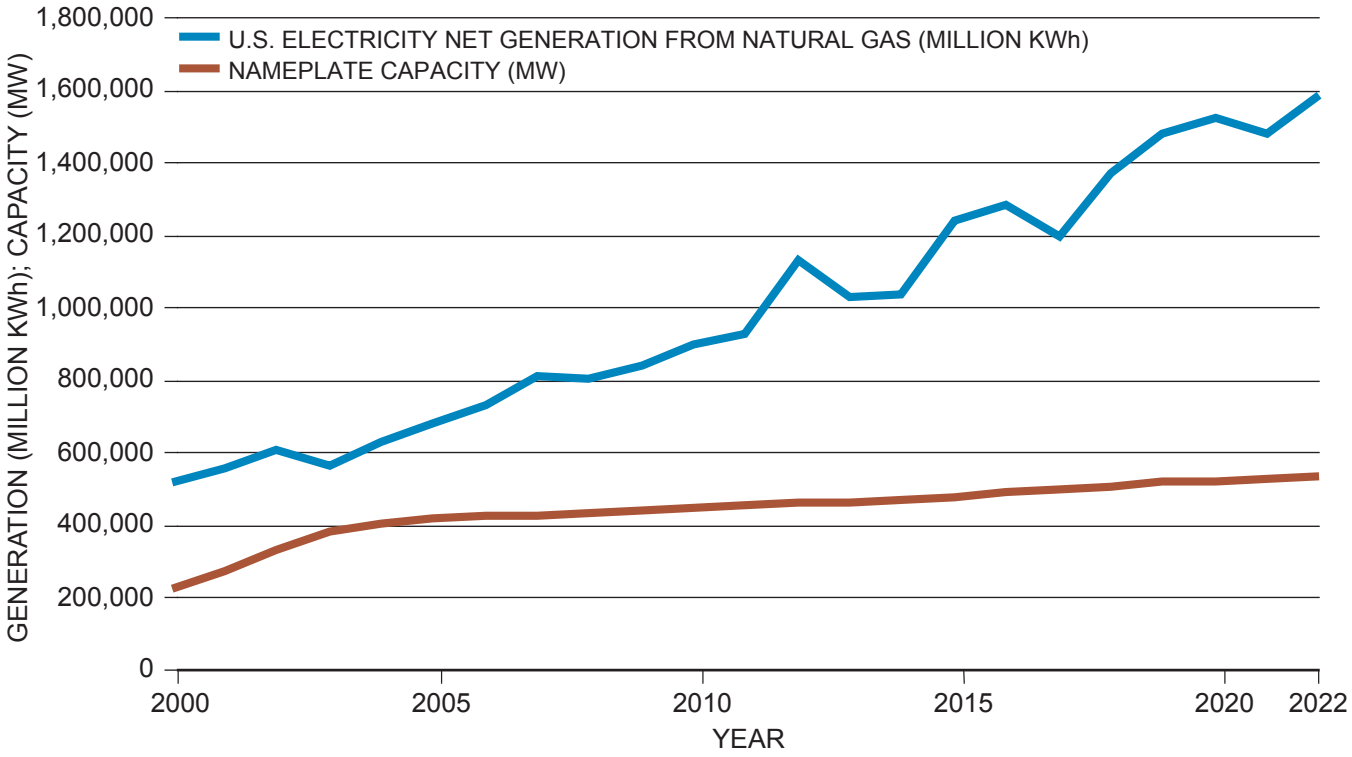
41 Data source: EIA, Monthly Energy Review, Table 7.2a Electricity Net Generation: Total (All Sectors). n.d. https://www.eia.gov/totalenergy/data/browser/?tbl=T07.02A#/?f=A.

42 Natural gas units have an average emissions rate of 898 pounds CO_2 per megawatt-hour (MWh), while coal units have an emissions rate of 2,180 pounds CO_2 per MWh. September 2019. https://www.epa.gov/sites/default/files/2020-12/documents/power_plants_2017_industrial_profile_updated_2020.pdf.

43 EPA. "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021." 2023. Table 2-4. https://www.epa.gov/system/files/documents/2023-04/US-GHG-Inventory-2023-Main-Text.pdf.

44 Haggerty, Mark. "The Evolution of U.S. Electricity Generation Capacity." Headwaters Economics. April 22, 2020. https://headwaterseconomics.org/economic-development/evolution-electricity-generation/.

45 *Unleashing American Power: The Development of Next-Generation Energy Infrastructure, Before U.S. House of Representatives Committee on Science, Space, and Technology*, 2023 (Spencer Nelson, Managing Director of Research and New Initiatives, Clearpath Action. https://www.congress.gov/118/meeting/house/115530/witnesses/HHRG-118-SY20-Wstate-NelsonS-20230323.pdf.



Source: EIA, 2024, "Electric Capacity and Generation, EIA-860A/860B."

Figure 1-10. *Electric Generation from Natural Gas*

supply of economically accessible natural gas resources in the United States and led to a commensurate reduction in the price of natural gas. Natural gas spot prices peaked in 2008, as illustrated in Figure 1-11, and dropped to below $4 per million British thermal units (MMBtu) in 2009, where it has largely remained until the end of 2021. Due to the buildout of shale gas resources domestically, the United States has not seen inflationary pressures compared to other aspects of the economy due to abundant supply. As shown in Figure 1-12, natural gas pricing in the United States has remained significantly below international gas pricing benchmarks over that same period.

The steep price decline and increase in natural gas capacity led to a sharp decline in coal-fired electricity beginning in 2008. While total electricity consumption has remained relatively flat since the financial crisis in 2008, coal use has declined steadily and has been primarily replaced by natural gas generation and, more recently, solar and wind generation (Figure 1-13). Ultimately, natural gas surpassed coal to become the largest fuel source of electricity in 2015. In 2021, 1,500 terawatt hours of electricity were generated from natural gas combustion, an 80% increase since 2008. Over the same period, wind and utility-scale solar capacity increased by 700% and generated a total of 493 terawatt hours in 2021.[46]

Additionally, according to the EIA, "of the 819 million metric ton decline in CO_2 emissions from 2005 to 2019, approximately 248 million metric tons (30%) of that decline is attributable to the increase in renewable generation. In comparison, almost 532 million metric tons (65%) of the decline in CO_2 emissions is attributable to the shift from coal-fired to natural gas-fired electricity generation.[47] The mode of natural gas generation has also contributed to the decrease

46 EIA. Electricity Data Browser. n.d. https://bit.ly/4a9WdYK.

47 EIA. "Electric Power Sector CO_2 Emissions Drop as Generation Mix Shifts from Coal to Natural Gas." June 9, 2021. https://www.eia.gov/todayinenergy/detail.php?id=48296.

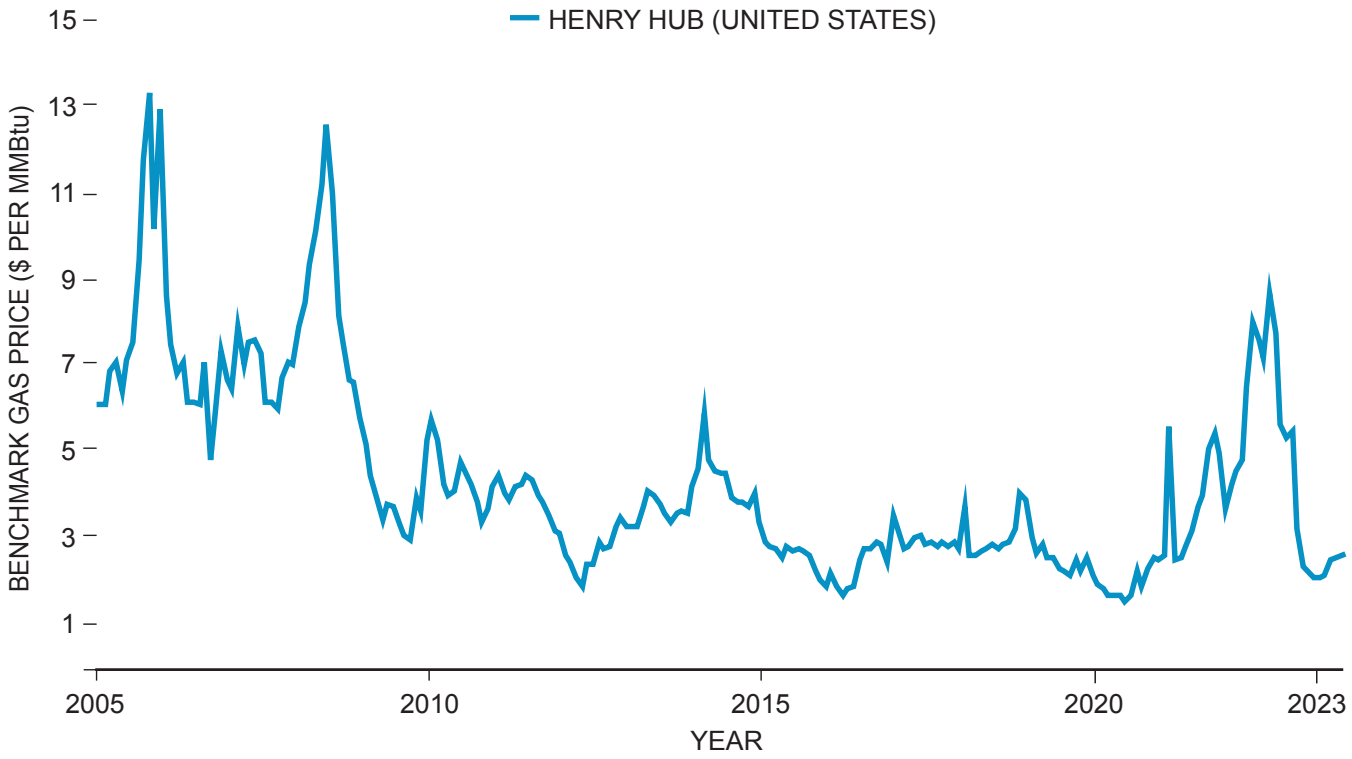


Figure 1-11. *Monthly Time Series of U.S. Gas Benchmark Price at Henry Hub*

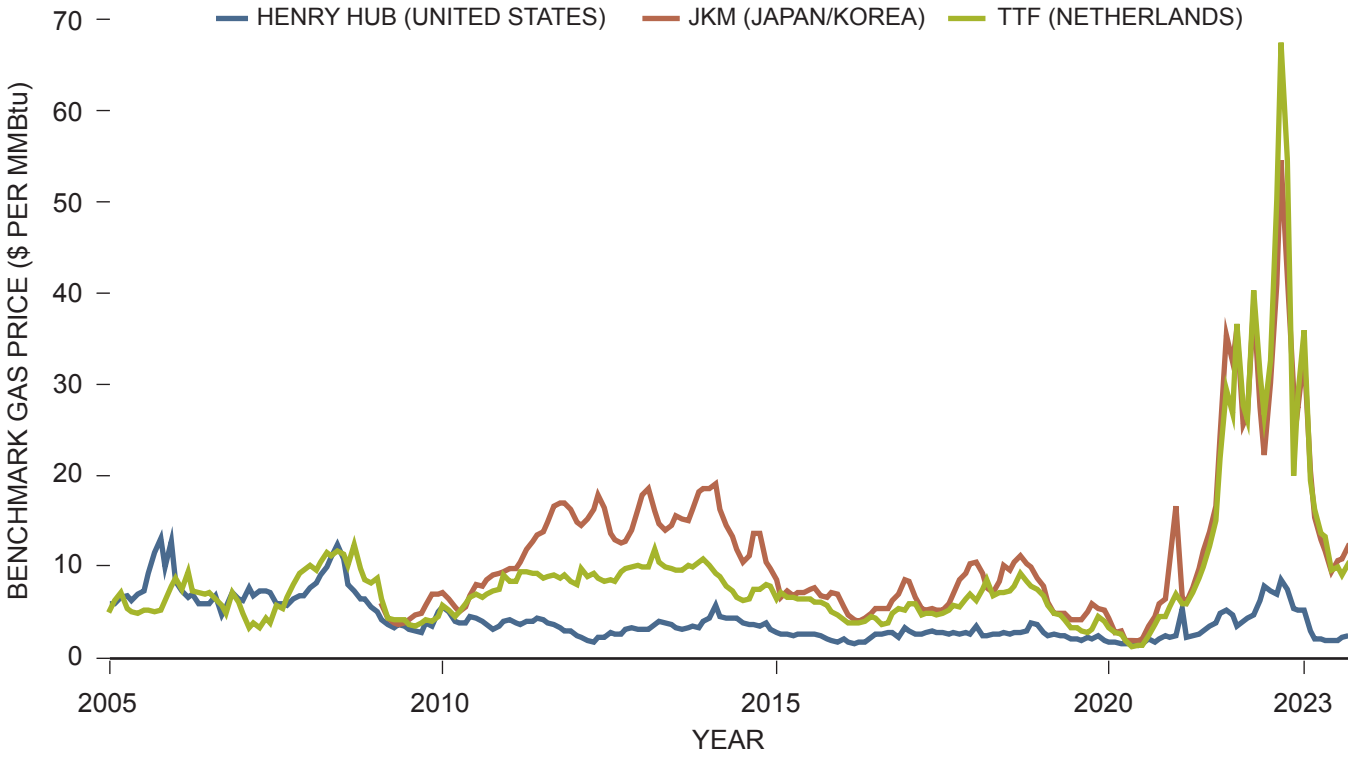
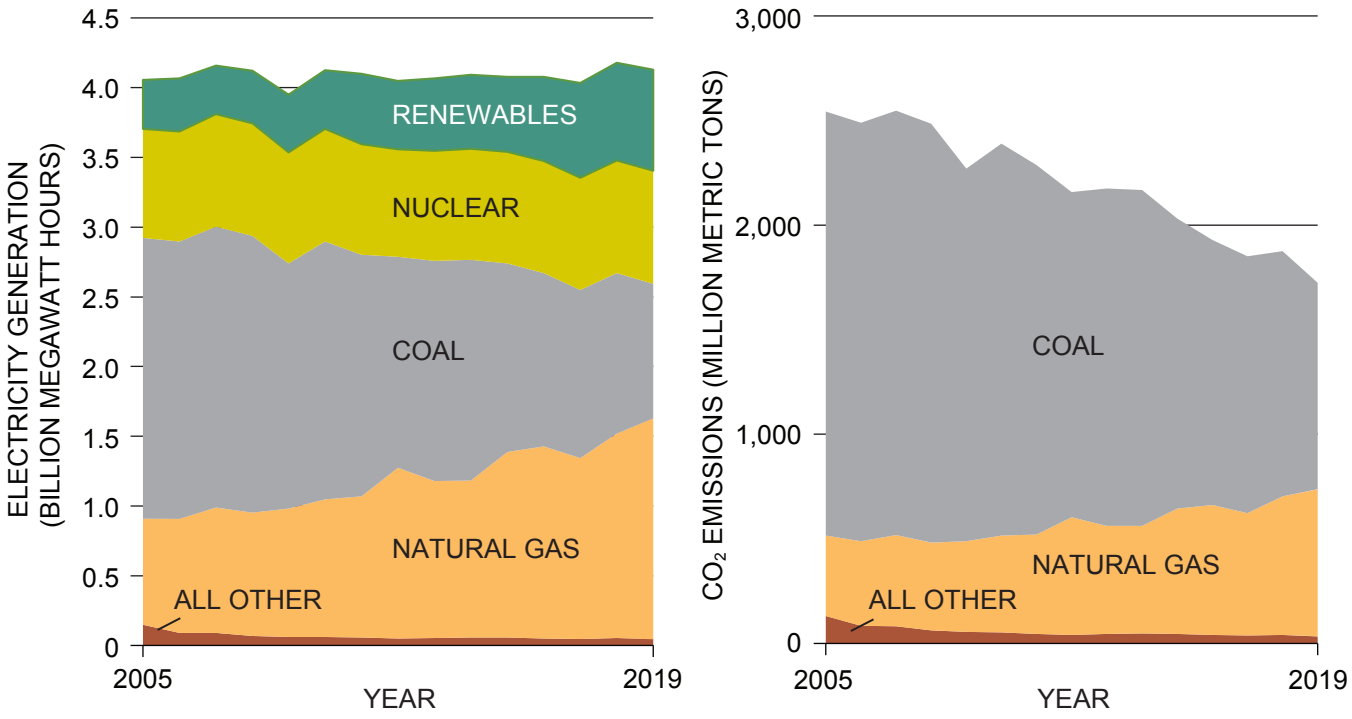


Figure 1-12. *Monthly Time Series Comparison of Gas Benchmark Pricing Between the United States, Europe, and Asia Regions*



Note: Electric power sector CO_2 emissions drop as generation mix shifts from coal to natural gas.

Source: EIA, "Power Plant Operations Report."

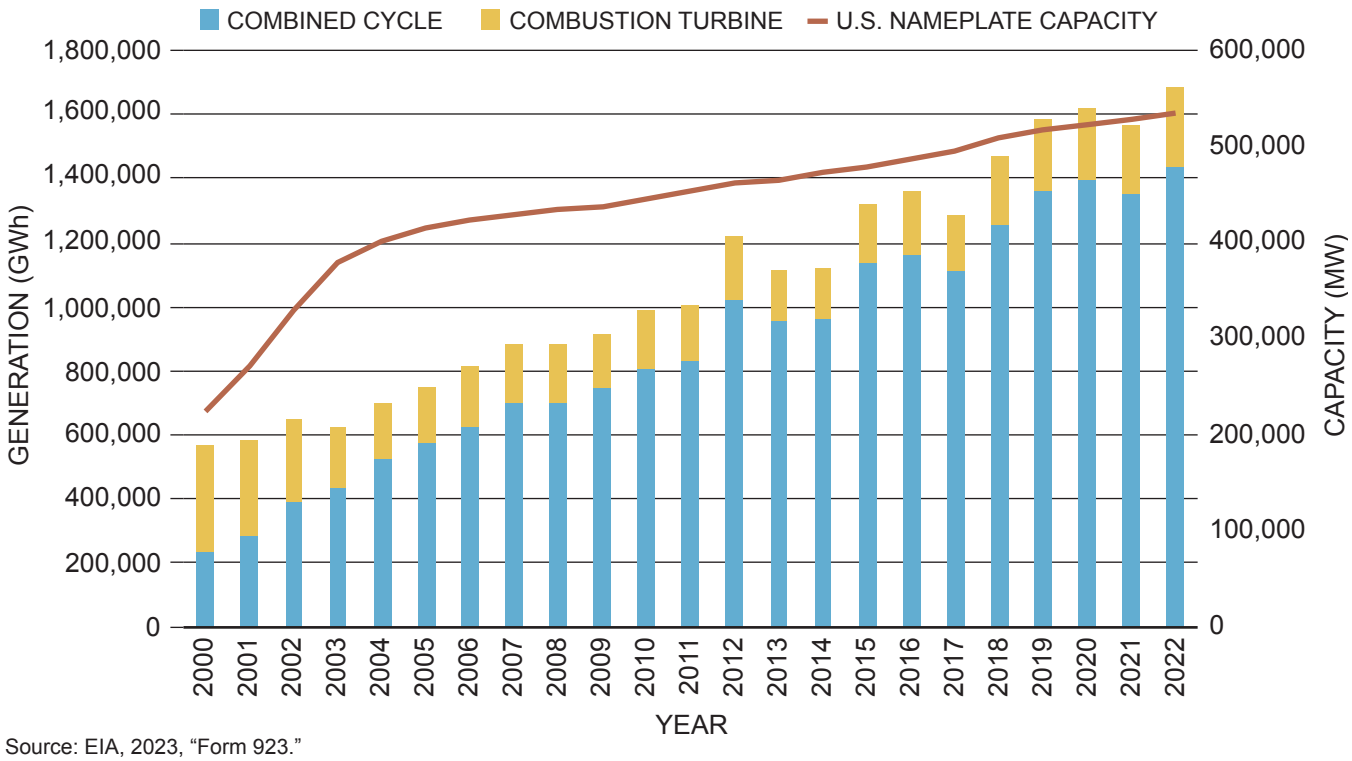
Figure 1-13. *U.S. Net Electricity Generation and Carbon Dioxide Emissions from Selected Sources*

in CO_2 emissions in the electricity sector. Two types of generation modes are commonly used: (1) Combined-cycle (CC), which consists of both a combustion turbine and heat recovery steam generation turbine; and (2) Simple-cycle (SC), which consists of a combustion turbine only. CC typically has greater fuel efficiency. CC is generally used for baseload while SC is used for peaking/on-demand supply. SCs are largely being built to support intermittent grid supply or to support periods of peak demand. The shale gas revolution provided a steady supply of low-cost natural gas, which allowed CC units to become baseload generators of electricity based on economic factors. CCs are also more efficient than SCs, emitting less CO_2 emissions per unit of electricity generated. For example, assuming an efficiency of 51% for a CC, the projected CO_2 emissions rate would be 384 metric tons of CO_2/MWh and assuming an efficiency rate of 34% for a SC, the expected emissions rate would be 584 metric tons of CO_2/MWh. As shown in Figure 1-14, CCs have represented the majority of the natural gas-based power generation in the United States since 2002 and been the main driver of growth in natural gas power generation over the last two decades.

FINDING 5: Natural gas displacing coal reduced U.S. emissions by 532 million metric tons of CO_2 or 65% of the U.S.'s total CO_2 reduction from 2005 to 2019 according to the EIA.

FINDING 6: Natural gas-fired capacity from 2000-2005 (192 GW) increased because deregulation of electricity markets paved the way for significant coal-to-gas switching when shale gas production ramped up in 2008 and beyond.

FINDING 7: Further reduction in the GHG intensity of the U.S. natural gas supply chain is needed to enhance this national GHG reduction benefit.



Source: EIA, 2023, "Form 923."

Figure 1-14. *Natural Gas-Fired Capacity and Electric Generation from Natural Gas*

C. GHG Emissions from the Natural Gas Supply Chain

1. Relative GHG Emissions Rates for the Sector

The EPA creates an annual inventory of all U.S. GHG emissions, including its estimates for emissions from the natural gas system. Consistent with IPCC national inventory best practice guidance, combustion emissions and noncombustion emissions, including flaring, venting, and fugitive emissions are tracked in separate sections of the U.S. GHG Inventory (GHGI). GHG emissions that have been analyzed in this chapter are included within the following categories of the GHGI:

- **Natural Gas Systems:** emissions associated with the natural gas supply chain, excluding end use. Postmeter emissions are not included within analyses in this chapter.
- **Petroleum Systems:** emissions associated with the crude oil and petroleum products supply chain, excluding end use. This study covers emissions from oil production but not transport or refining, which are outside the scope of the natural gas supply chain. Petroleum production facilities have similar, but not identical, sources of emissions, abatement options, and regulatory requirements as natural gas production facilities.
- **Abandoned Oil and Gas Wells:** Emissions associated with plugged and unplugged wells at the end of their economic life are included in analyses in this chapter.
- **Natural Gas Combustion:** emissions associated with the use of natural gas for energy. This chapter analyzes a subset of emissions related to the combustion of natural gas within the supply chain. This includes lease fuel associated with the production and gathering of oil and gas, plant fuel used in the natural gas processing sector, and pipeline and distribution fuel use that account for energy use in transmission, distribution, and LNG plants. At the national level, it is difficult to distinguish lease fuel use

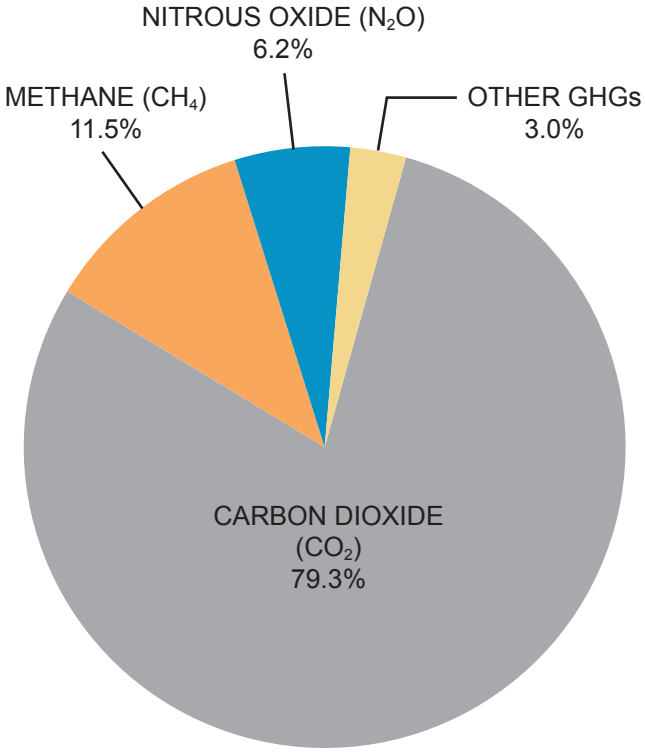
between the petroleum and natural gas production sectors in EPA and EIA data.

GHGI data for 2021 shows that emissions within these study boundaries represent 5% of national carbon dioxide emissions, 33% of national anthropogenic methane emissions, and 8% of national net GHG emissions. Across all sectors, carbon dioxide is the primary GHG at more than 79% of total emissions. Methane (~12%) and nitrous oxide (~6%) are also important GHG emissions at the national level across various sectors (Figure 1-15).

This study does not address pathways to reduce the GHG emissions associated with the combustion of natural gas for end use outside of the natural gas supply chain, which were ~28% of U.S. carbon dioxide emissions in 2021. End-use emissions require different types of integrated modeling tools that assess cost, carbon budgets, and substitution availability, which varies by end-use application. Reducing the methane and carbon dioxide intensities of natural gas supply chains is important work for the U.S. natural gas and petroleum industries, regardless of end-use levels.

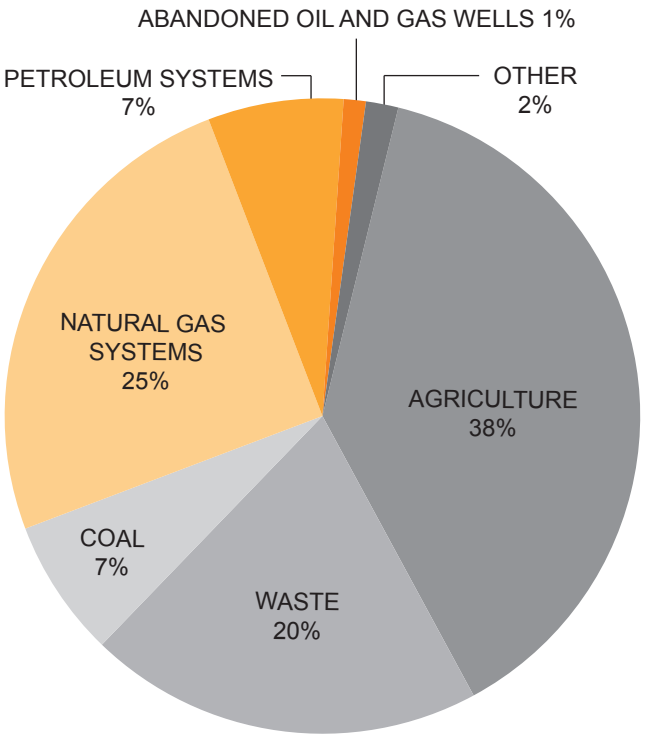
The following sections examine the breakdown of carbon dioxide and methane emissions from the petroleum and natural gas supply chains to better understand the contributing factors toward the GHGI. Figure 1-16 shows the sector-level breakdown of anthropogenic, or human-caused, methane emissions in GHGI data for 2021. Overall, agriculture is the largest source of methane emissions (38%), with key contributions from livestock and rice cultivation. Waste (20%), which includes landfills and wastewater treatment, and coal mining (7%) are also key contributors to national methane emissions estimates.

Approximately one-third of anthropogenic methane emissions occur from sources analyzed in this chapter. Methane emissions within the natural gas system (25%) and petroleum systems (7%) are included in Figure 1-16 to show the overall contributions as tracked by EPA in the GHGI. Methane emissions in natural gas and petroleum systems include venting, flaring, and fugitive emissions. EPA estimates that ~1% of U.S. anthropogenic methane emissions are from abandoned wells, which includes both plugged and



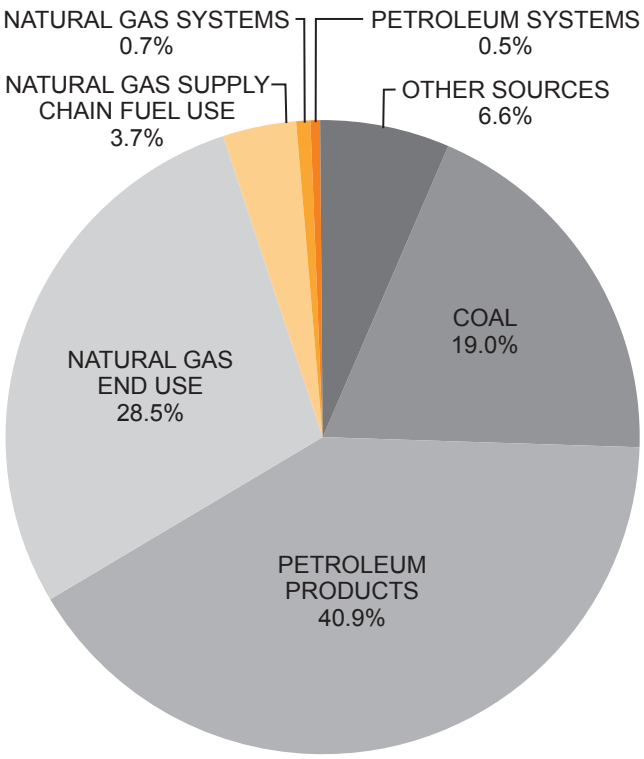
Source: EPA, 2023.

Figure 1-15. *Percentage of U.S. Total GHG Emissions by Individual GHG in 2021*



Source: EPA, 2023.

Figure 1-16. *Percentage of U.S. Total Anthropogenic Methane Emissions by Sector in 2021 from GHGI (EPA Greenhouse Gas Inventory)*



Source: EPA, 2023.

Figure 1-17. *Percentage of U.S. Total Carbon Dioxide Emissions by Sector in 2021*

unplugged wells. More detailed emissions profiles for the sector are included in later sections of this chapter.

The study will include absolute emissions associated with the natural gas supply chain and with petroleum production since the emissions reduction technologies, regulations, and GHG reporting mechanisms typically do not distinguish between oil, natural gas, and natural gas liquids at the production, gathering, and processing stages. Some intensity views, particularly in Chapter 4, will include coproduct allocation, which assigns emissions to individual products. Recommendations to reduce GHG emissions associated with natural gas production may also apply to many assets focused primarily on oil production.

2. Carbon Dioxide Emissions

Figure 1-17 shows the sector-level breakdown of carbon dioxide emissions in GHGI data for 2021, with a focus on fuel use. Alternative views with emissions by economic sector and activity are available in the GHGI. Overall, the use of petroleum products (41%) like diesel and gasoline was the largest source of U.S. carbon dioxide emissions in the GHGI in 2021. In the same year, coal use was ~19% of total U.S. carbon dioxide emissions. Overall, natural gas combustion was ~32% of U.S. carbon dioxide emissions with ~4% of national emissions coming from energy use in the natural gas supply chain.

For carbon dioxide, noncombustion carbon dioxide emissions from petroleum and natural gas systems are ~1.2% of national emissions, including contributions from flaring, venting, and fugitive emissions throughout the supply chain.

3. Overall GHG Emissions

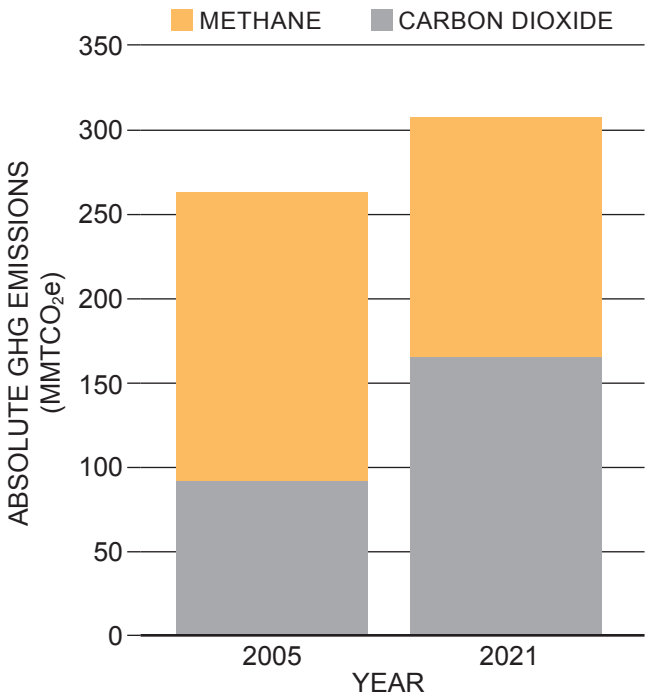
The GHGI tracks emissions of individual GHGs separately but also combines GHG emissions for tracking overall economy-wide reductions compared to 1990, which was the start of UNFCCC inventory reporting, and 2005, which is the base year for U.S. nationally determined contribution reductions, using a 100-year global warming potential (GWP100), which is discussed later in this chapter. Nationally, two types of GHG emissions are measured: gross emissions and net emissions. Gross emissions refer to the total GHGs emitted across all sectors, while net emissions are calculated by subtracting GHG emissions sinks from the gross emissions. In the GHGI, emissions sinks are primarily driven by carbon storage as part of land use, including reforestation and the conversion of croplands to grassland, and were estimated as ~12% of gross GHG emissions in 2021. In 2021, sources within the scope of this study represent ~8% of net GHG emissions and ~7% of gross GHG emissions. While outside the scope of this study, natural gas end use accounted for 23% of gross GHG emissions and 26% of net GHG emissions (Figure 1-18).

4. Historic Changes in Emissions and Emissions Intensity Levels

The National Determined Contribution for the United States includes a commitment to reduce net GHG emissions by 50%-52% by 2030, relative to a 2005 baseline. As described in previous sections, oil and gas production levels in the United States have changed significantly since 2005. Compared to 2005, domestic production levels in 2021 have

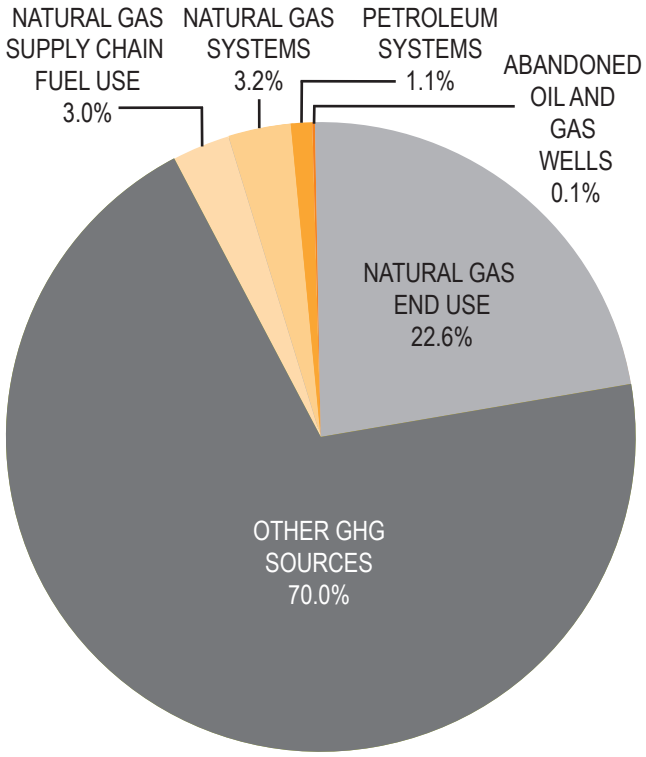
approximately doubled for crude oil and natural gas and more than tripled for natural gas liquids (NGLs). For a product-based view, some emissions within the study baseline would be allocated to crude oil and NGLs as part of a life cycle assessment. Figures 1-19 and 1-20 contain a simple energy-based allocation of GHG emissions in different segments of the supply chain (production, processing, etc.) based on the relative products present and the NPC analysis of data in the EPA GHGI and national EIA energy statistics. More detailed information on life cycle assessments for U.S. natural gas are covered in Chapter 4.

On an absolute GHG emissions basis, emissions allocated to the natural gas supply chain have increased by 17% since 2005. This was primarily driven by an ~80% increase in carbon dioxide emissions, primarily associated with energy use to produce and transport more natural gas. Action to date by the natural gas industry as well as state and federal regulators has already reduced methane emissions by ~17% on an absolute basis since 2005 through operational improvements such as flaring reductions,



Note: Based on NPC analysis of data from the U.S. GHGI and production statistics from EIA.

Figure 1-19. *Change in GHG Emissions Allocated to Natural Gas Between 2005 and 2021*

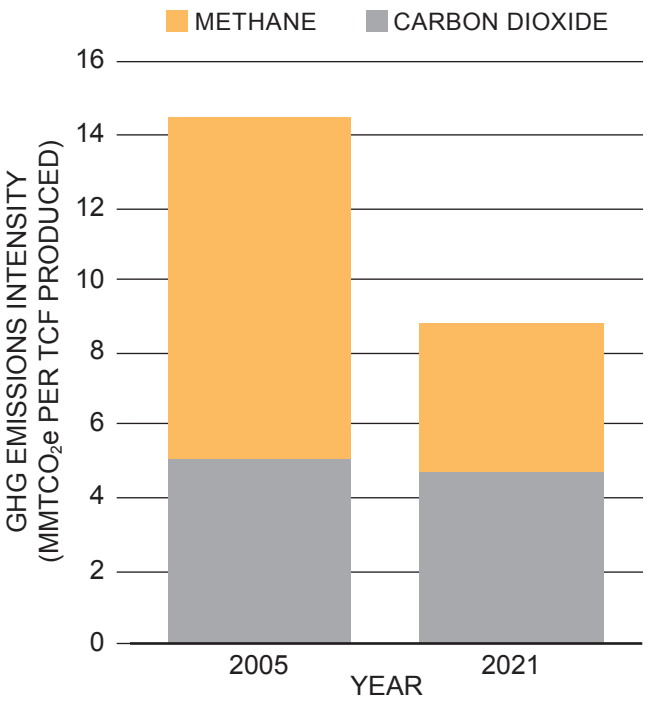


Source: EPA, 2023.

Figure 1-18. *Percentage of U.S. Gross GHG Emissions by Sector in 2021*

pneumatic device changeouts, and reduced emissions techniques during completions, despite the growth in production volumes.

As shown in Figure 1-20, the GHG emissions intensity of the natural gas supply chain was 39% lower in 2021 compared to 2005, with methane intensity down more than 57%. Carbon dioxide intensity levels were ~6% lower than in 2005, despite a buildout of an entirely new supply chain segment (LNG exports) during that period. In 2005, the United States was a significant net importer of natural gas with volumes being equal to ~20% of domestic natural gas production, and many emissions in these international supply chains would not be included in U.S. GHG emissions estimates, since they occurred in another country. By contrast in 2021, net exports of natural gas were approximately 11% of domestic natural gas production. From a GHGI perspective, export volumes would have supply chain emissions in the United States, but end-use emissions would be counted in inventories in the importing countries, if they are combusted.



Note: Based on NPC analysis of data from the U.S. GHGI and production statistics from EIA.

Figure 1-20. *Change in GHG Emissions Intensity Allocated to Natural Gas Between 2005 and 2021*

FINDING 8: **As production has grown in the United States, absolute methane emissions have been decreasing from the supply chain. Carbon dioxide and methane emissions intensities for the U.S. natural gas supply chain have also decreased since 2005.**

D. Descriptions of the Natural Gas Supply Chain

The natural gas supply chain is complicated as, throughout the supply chain, there are numerous different operators and transfers of custody. In a simple model (Figure 1-21), the natural gas supply chain can be described as a sequence of three segments that begin at a single wellhead and end at a consumer. These segments are production, transmission and storage, and distribution and are described briefly in the following sections.

1. Production

Natural gas comes from a wellhead and has widely varying composition depending on the production field and its reservoir characteristics. Natural gas can either be the primary product of the well or coproduced alongside oil or other hydrocarbon liquids, where it is known as associated gas. Wellhead natural gas may be dry natural gas or wet natural gas depending on the characteristics of the formation. Natural gas that is wet natural gas contains methane, NGLs—ethane, propane, butanes, and pentanes—and water vapor. Wellhead natural gas may also contain nonhydrocarbons such as sulfur, helium, nitrogen, hydrogen sulfide, and carbon dioxide, most of which must be removed from natural gas before it is sold to consumers or transported over long-distance pipelines. Dry gas, or consumer-grade natural gas, is mostly methane, usually 85% or more, and contains only negligible amounts of dissolved liquid hydrocarbons and impurities.

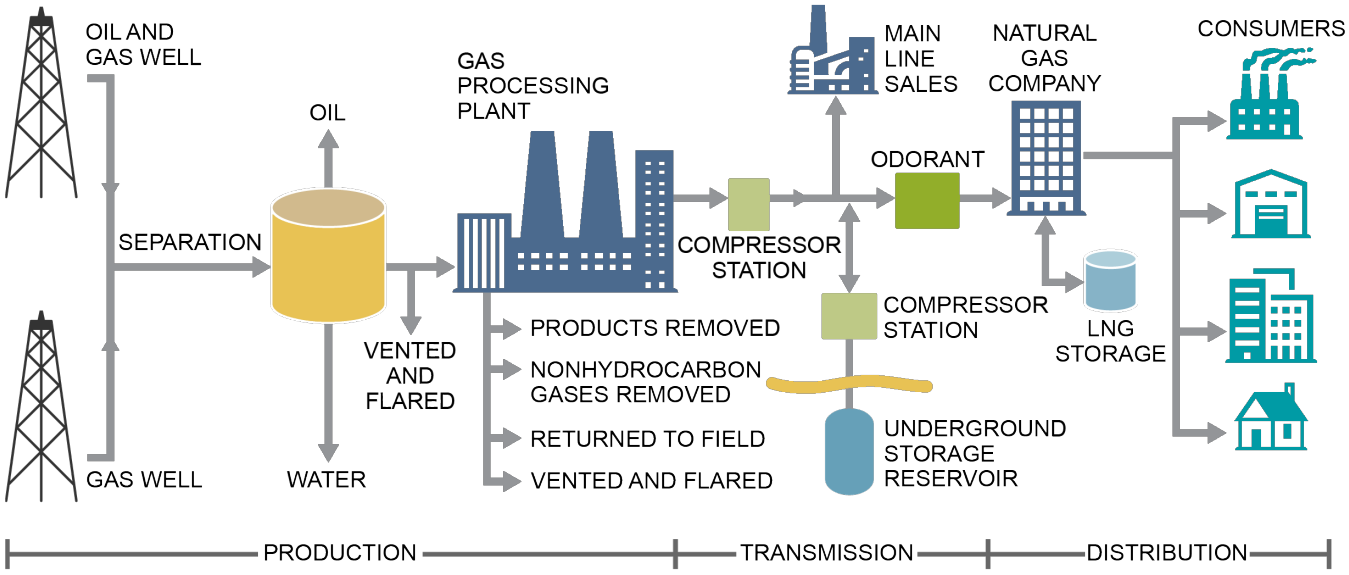
Natural gas typically moves from production sites (natural gas and oil wells) through a network of small-diameter gathering pipelines to natural gas processing for removal of impurities, such as carbon dioxide and water, and separation of the NGLs, which are sold separately. Some ethane may be left in processed natural gas, which is dry, consumer-grade, and pipeline-quality.

2. Transmission and Storage

Natural gas transmission pipelines are wide-diameter pipelines and are often the long-distance portion of natural gas pipeline systems that connect gathering systems in producing areas, natural gas processing plants, and other receipt points to the main consumer service areas. There are three types of transmission pipelines, differentiated by the regulatory regime governing their commercial operations:

- Interstate natural gas pipelines operate and transport natural gas across state borders.
- Intrastate natural gas pipelines operate and transport natural gas within a state border.
- Hinshaw natural gas pipelines receive natural gas from interstate pipelines and deliver it to consumers for consumption within a state border.

Demand for natural gas fluctuates daily and seasonally, but production and pipeline movement



Note: This EIA figure combines distinct supply chain segments of production, gathering and boosting, and processing in one category for ease of display.

Source: EIA.

Figure 1-21. *Elements of Natural Gas Production and Delivery*

are relatively constant in the short term. Natural gas storage during periods of low demand helps to ensure that enough is available during periods of high demand. Natural gas is stored in large volumes in underground facilities and in smaller volumes in tanks above or below ground. The United States uses three main types of underground natural gas storage facilities:

- **Depleted natural gas or oil fields:** Most natural gas storage is in depleted natural gas or oil fields that are close to consuming areas.
- **Salt caverns:** Most of the salt cavern storage facilities are in salt dome formations in the states bordering the Gulf of Mexico. Salt caverns have also been leached from bedded salt formations in states in the Midwest, Northeast, and Southwest.
- **Aquifers:** Water aquifers that have water-bearing sedimentary rock formations overlaid with impermeable cap rock are used as natural gas storage reservoirs, especially in the Midwest. These are typically very deep nontributary aquifers and do not impact drinking water.

Some high-volume consumers of natural gas, like utility-scale power plants, may utilize gas directly from the transmission sector without the distribution step in the next section.

3. Distribution and Liquefied Natural Gas

The distribution system is infrastructure that is mainly composed of small-diameter, low-pressure pipelines to deliver the natural gas product to many users. Often, these systems are operated by a local distribution company (LDC), which are typically regulated by a state's public utility commission. In the United States, specific regions tend to be served by an individual LDC, which delivers gas to homes, businesses, and other smaller-volume applications. LDCs typically take control of the gas at a city gate and add odorants to natural gas so that leaks in distribution pipelines can be detected.

In the past, U.S.-produced natural gas has predominantly been used by American domestic consumers. Recently, the export market for U.S. natural gas has expanded through the creation of LNG export terminals. LNG processing includes a liquefaction plant at which the natural gas is cooled to a temperature of -260°C before storage and shipment. In this state, LNG occupies only 1/600th of the volume it occupies as a gas, resulting in a stable, high-Btu product that can be shipped via specialized tankers to markets throughout the world.

E. Sources of Emissions in the Natural Gas Supply Chain

1. GHG Reporting Programs in the United States

In the United States, EPA maintains two complementary emissions reporting programs, which are the GHGI and the GHGRP. A breakdown of the differences between the two reporting programs is outlined in Table 1-2.

The GHGI is the official record of U.S. GHG emissions that is developed by EPA and provided to the UNFCCC as part of country-level GHG reporting efforts. Emissions estimates are developed for all economic sectors as well as changes in anthropogenic emissions sinks like land use and has time series information back to 1990. As part of the development of the GHGI, EPA accounts separately for emissions associated with natural gas and petroleum systems on a source-by-source basis within each segment of the oil and gas supply chains at the aggregate national level. The GHGI process to differentiate between natural gas and petroleum systems is difficult due to the associated gas of petroleum systems. Multiple types of information inform EPA's GHGI estimate, including emissions information reported by companies under the GHGRP, energy sector data collected by the EIA, and statistical population data, such as the number of U.S. households or cattle, to make GHG estimates for different sectors. The GHGI is publicly released on an annual basis in April for the year that ended

	GHGI	GHGRP
Coverage in oil and gas sector	100% coverage of all supply chain segments	Reporters with annual emissions above 25,000 metric ton CO_2e by facility (definition varies across supply chain segments)
Noncombustion data public availability (e.g., methane, flaring, and venting)	As part of its publication of the GHGI, EPA includes spreadsheets with its source-specific assessments of methane and carbon dioxide emissions from noncombustion sources (flaring, venting, and fugitives) for natural gas and petroleum systems.	Source-level data by operator is available; some sources included in GHGI are not included in GHGRP.
Data associated with combustion sources	Not included in oil and gas supply chain segments but as part of natural gas combustion emissions at the lease, plant, and pipeline/distribution granularity	Generally included in operator reporting in Subpart C or Subpart W
Breakout of emissions from oil and gas	EPA does the allocation between oil and gas	Emissions reported by segment at basin level would need energy-based allocation to breakout
Basin-level data	Only for flaring and venting in select basins (Eagle Ford, Bakken, Permian)	Data are reported at the basin level in current program
Source-specific emissions data	National total	Asset level
Data collection process	EPA uses GHGRP and other sources to develop national estimates for two years prior. Typically released in April each year	Annual reporting by operators in March; EPA verifies and publicly releases in the fourth quarter
Process for changing calculations	EPA public review process	EPA Rulemaking
Submitted to UNFCCC as national baseline	Yes	No
Includes abandoned well emissions estimates	Yes	No

Table 1-2. *Comparison of GHGI and GHGRP Methodologies*

approximately sixteen months prior (i.e., 2021 data was released in April 2023).

Reporting guidance under the UNFCCC is divided into three tiers based on the complexity and national specificity of emissions estimates provided. Emissions from the oil and gas sector globally is often reported at the Tier 1 level, which utilizes high-level national emissions factors and production rates that do not differentiate between different types of operations or the equipment on specific sites. Methodologies used by EPA in the GHGI are considered Tier 3, which is the highest reporting tier and is used by relatively few countries globally in their UNFCCC submissions. While the GHGI does rely on emissions factors and activity data to drive many calculations, the emissions factors have often been developed from U.S.-specific measurement campaigns and involve national counts of devices (pneumatic controllers, compressors, etc.) or activity data like flaring volumes to drive calculations.

As part of the annual GHGI report development cycle, EPA has a public review process that solicits feedback on specific proposed changes to methodologies and hosts sector-specific workshops focusing on petroleum and natural gas systems to gather information that may be useful for future inventory updates. Thus, the information used in developing the GHGI is not static, but EPA typically limits itself to methodologies for which it can make backcast estimates to make a consistent submission to the UNFCCC and comparisons past years. Recent updates to the GHGI have included the use of more specific measurement data for some sources, such as flaring intensity volumes in key oil production basins and one-time additions of methane emissions estimates from documented well blowouts. EPA intends to continue updating and refining methodologies in the GHGI, including investigations of historic satellite information to attempt to understand the historic frequency of larger emissions events.

2. GHGRP Methodology

The EPA Greenhouse Gas Reporting Program (GHGRP) was established in 2010 and provides sector-specific emissions reporting. For the GHGRP, EPA issues rules that define specific reporting criteria for facilities in different sectors. For the natural gas sector, emissions are generally reported under Subpart C[48] for larger combustion sources and Subpart W[49] for other GHG emissions sources, including sources of methane emissions. EPA has made periodic updates to methodologies and parts of the natural gas system, such as the addition of gathering and boosting in 2016, since the start of the GHGRP program. Under the GHGRP, operators report emissions in March for the previous year (i.e., 2022 annual emissions were reported in March 2023) and most of the detailed emissions results and calculation inputs are publicly released on the EPA website in the fourth quarter of the same year. Between March and the public release date, EPA conducts a verification process on submitted reports and asks submitters to resolve questions.[50] Compared to other national GHG reporting programs in other countries, the GHGRP is unique in the amount and detail of information that is released to the public on an annual basis, including the ability to look up asset-specific information by source and the calculation methods and inputs from individual GHG reporters.

In developing the GHGRP, EPA has historically recognized the need to balance information collection to support an understanding of U.S. GHG emissions from industrial sectors with a desire to not unduly burden small businesses. This balance is primarily implemented using a facility definition with a reporting threshold, which under 40 CFR 98[51] is generally set at annual emissions exceeding 25,000 metric tons of carbon dioxide equivalent emissions.

Due to the dispersed nature of the U.S. oil and gas sector, relatively few sites under a traditional

48 EPA. "Calculating CO_2 Emissions from Combustion." 2015. https://www.epa.gov/sites/default/files/2015-05/documents/subpartcmethodologiesfactsheet.pdf.

49 EPA. "Fact Sheet for Subpart W Petroleum and Natural Gas Systems Proposed Mandatory Reporting of Greenhouse Gases Rule." March 2010. https://www.epa.gov/sites/default/files/2015-05/documents/subpart-w_factsheet.pdf.

50 EPA. "Greenhouse Gas Reporting Program Report Verification." n.d. https://www.epa.gov/sites/default/files/2017-12/documents/ghgrp_verification_factsheet.pdf.

51 "40 CFR Part 98 Subpart A." *Code of Federal Regulations* (last amended March 19, 2024): https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-A.

fence-line definition would reach this threshold and need to report emissions. Thus, the GHGRP program defines a facility for GHG emissions reporting purposes in the oil and gas sector as an aggregation of individual sites with the same operator within a specific geography and segment. Examples of geographic boundaries include a basin for the production and gathering and boosting segments and a state for the distribution segment. Within the same basin, emissions from production and gathering and boosting are reported separately. To better represent the geographic area where these emissions occur and provide easier access to information for the sector, the online EPA tool, known as FLIGHT,[52] can filter results to individual segments and basins.

The GHGRP prescribes methodologies that reporters must use to calculate GHG emissions from each source category, although there is often some flexibility to choose among several methods for the same source category. The decision of which method to use may be influenced by the existing data availability and other factors. Reporters can change emissions calculation methods from year to year, if they meet the requirements for use of the method selected.

Since the GHGRP began, EPA has updated the coverage, source, categories, and methodologies for Subpart W reporting as shown in Figure 1-22. The first few years of reporting in the program included the ability to substitute Best Available Monitoring Methods[53] for required methodologies with specific equipment counts and measurements to give time for operators to develop new reporting and recordkeeping systems. Subsequent updates included the addition of new emissions sources, like gathering and boosting systems and oil well completions with hydraulic fracturing, as new information emerged about potential sources of GHG emissions in the natural gas supply chain and updates to align methodologies with new source performance standards leak detection and repair (LDAR) data. In 2023, EPA issue a proposed rulemaking with many updates to GHGRP methods for methane reporting that is summarized in discussions on federal methane regulations in this chapter.

52 EPA. "Facility Level GHG Emissions Data." August 18, 2023. https://bit.ly/49cjAzM.

53 EPA. "Greenhouse Gas Reporting Program Emission Calculation Methodologies." n.d. https://www.epa.gov/sites/default/files/2017-12/documents/ghgrp_methodology_factsheet.pdf.

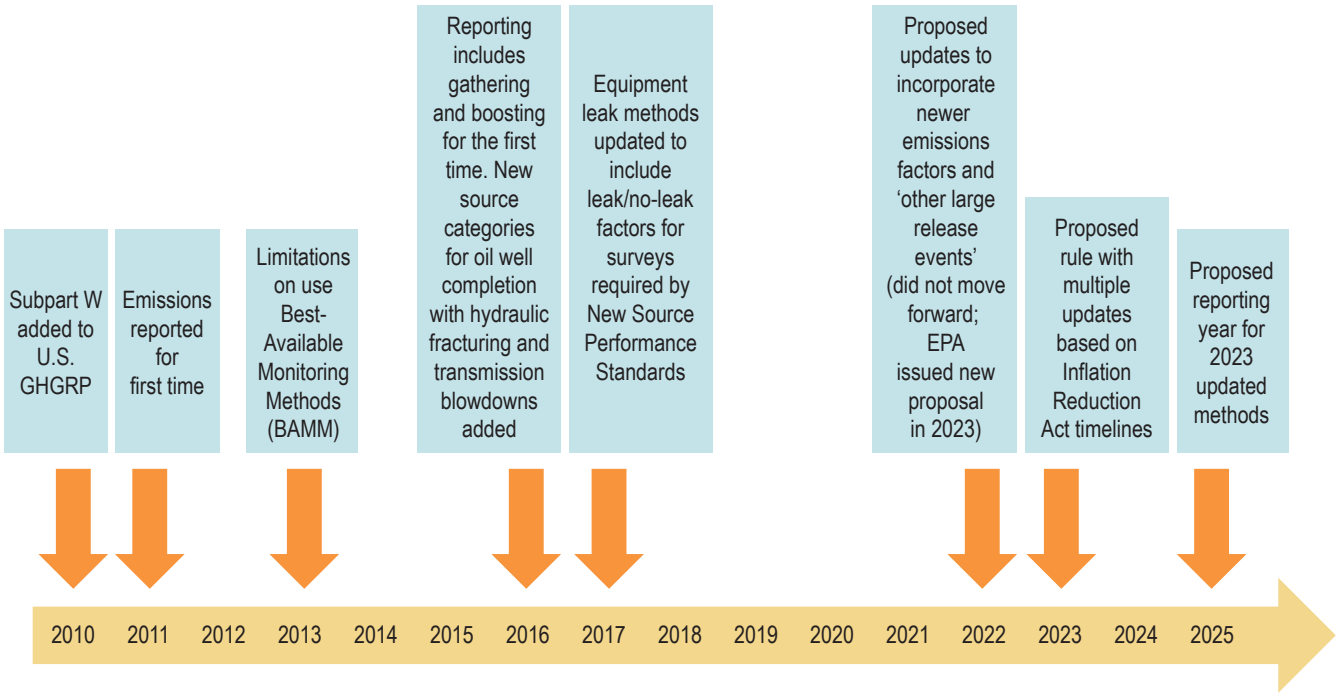
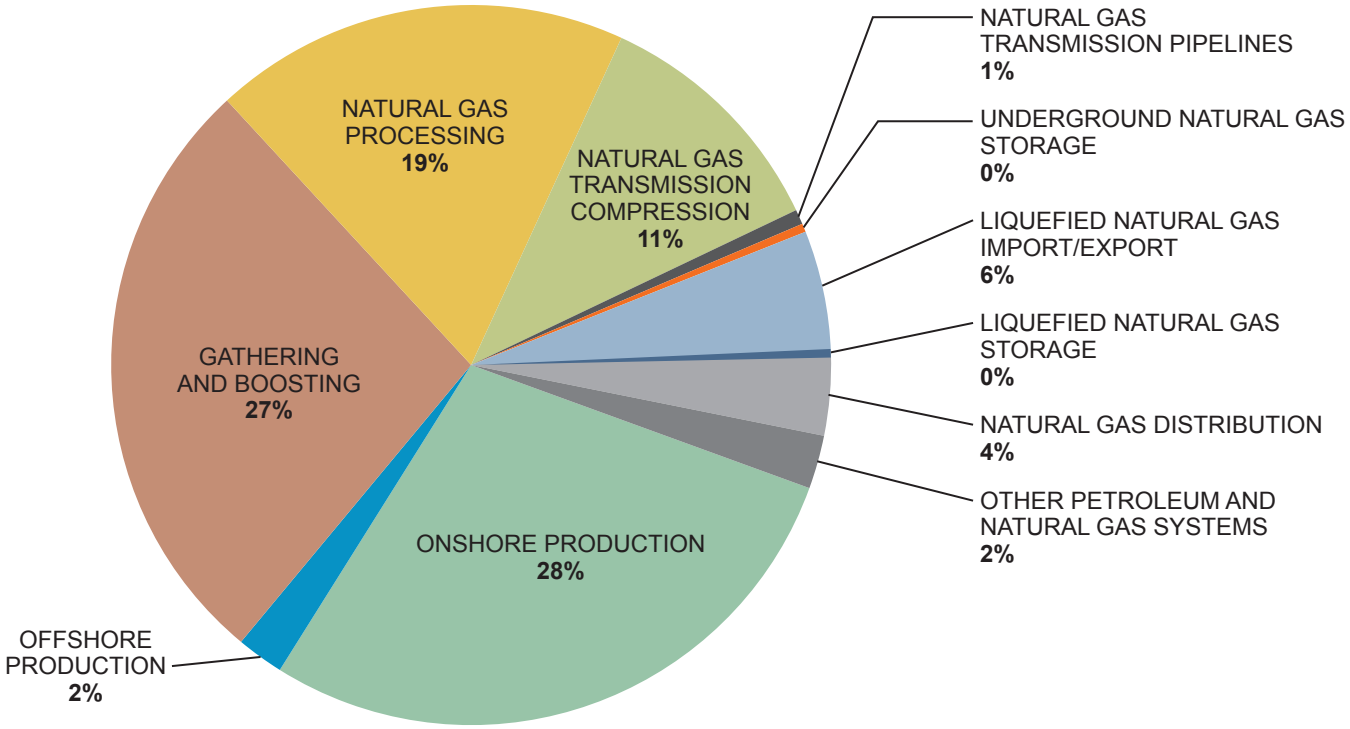


Figure 1-22. *Timeline of Example Changes to Subpart W Reporting in the GHGRP*



Source: EPA, 2023, "GHGRP Petroleum and Natural Gas Systems."

Figure 1-23. *GHG Emissions by Subsector in the GHGRP for the Oil and Gas Industry in 2022*

For emissions associated with combustion, site-specific fuel composition data can also be used for calculations. A facility using this methodology would use parameters for each fuel type, such the high heating value, carbon content, and (for gaseous fuels) molecular weight of a representative sample and determine their calculated emissions factor by multiplying these parameters by the quantity of fuel consumed. Facilities can also use default emissions factors supplied by the GHGRP that are a representative average based on samples of the fuel that have been taken across the country. In general, homogeneous fuels, such as pipeline-quality natural gas, often provide a very accurate default emissions factor as there is very little change to the gas composition over time.

In 2022, EPA received GHGRP data from more than 2,300 petroleum and natural gas facilities across the supply chain, including production, gathering, and boosting, processing, transmission, and distribution systems. In total, these emissions represented 11.5% of total reported GHG emissions under the program, which is focused on the collection of data from industrial sectors. Figure 1-23 shows the relative breakdown on emissions that are reported by supply chain segment under the petroleum and natural gas systems sector for the GHGRP.

3. Global Warming Potential

Each GHG has a unique atmospheric influence that is a function of both its atmospheric lifetime, which is the length of time that a GHG remains in the atmosphere, and its radiative efficiency, which is a measure of its efficiency at absorbing energy in the atmosphere. Generally, these two effects cannot be captured with perfect accuracy in a single scaling factor. Thus, reporting protocols, like the GHGRP, may require tracking individual species. However, in some instances, a metric is required where different GHGs can be tracked together. For example, in reporting total GHG emissions as the sum of carbon dioxide emissions and methane emissions, or in comparing the merits of a program that reduces

gas flaring (resulting primarily in carbon dioxide reductions) against a program that reduces gas venting (resulting primarily in methane reductions), a metric that allows carbon dioxide and methane to be tracked together is necessary.

While there are a variety of different comparative metrics with different trade-offs that are summarized in detail in *IPCC Assessment Reports*, the most common metric is the global warming potential (GWP), which is a simple scalar that equates the climate impact of a unit mass of a GHG to a particular mass of carbon dioxide. Essentially, the GWP adds up all the heat trapped by a GHG over a certain period and compares that to the heat trapped by carbon dioxide over the same period of time. Example GWPs for different gases and different periods of time are shown in Table 1-3 for the most common GHGs in the oil and gas sector.[54]

Developed in the 1980s, the GWP was not intended to be a tool for policy making but instead was adopted to illustrate the difficulties inherent in the attempt to create a single scalar to compare GHGs; nevertheless, GWP was utilized in policy as early as the Kyoto Protocol, due to the need to compare different GHGs using a simple metric. Today, GWPs are commonly used in the development of national GHG inventories, including the annual inventory developed by EPA, and for assessing emissions reduction opportunities across sectors and gases.

54 "Global Warming Potentials (GWPs)/CO_2-Equivalent (CO2e) and the Importance of Time Horizons." n.d. https://www.edf.org/sites/default/files/content/emission_equivalency_tool_documentation_methodology_23062022.pdf.

While it is widely used in policymaking, there is criticism of the GWP metric that often centers on the choice of timeframe (i.e., the period of time in which the heat trapping is added up) that the metric user wishes to consider the effects of warming. Any timeframe could be chosen for the assessment of GWPs, and no single choice is more scientifically correct. All choices would be a simplification of complex and dynamic atmospheric processes. Different decisions on GWP or related metrics have trade-offs, often in terms of what a stakeholder wishes to prioritize within the range of GHG reduction decisions. Thus, it is a policy decision, at the national or subnational level, for which metric is most appropriate for weighing the different trade-offs.

As a result, different organizations have adopted different GWP timeframes. Initially the Kyoto Protocol selected the 100-year timeframe because it was the middle one of three timeframes available (20, 100, and 500 years). At COP27 in 2022, representatives from all countries that are party to the UNFCCC reaffirmed the existing utilization of the 100-year time horizon for UNFCCC reporting and agreed to update from Assessment Report 4 (AR4) to AR5 factors, excluding the adjustment value for fossil methane. Assessment Reports are created by the IPCC over a several-year cycle to summarize scientific knowledge around various topics related to climate change, including comparison metrics like GWP. Since COP27, EPA has updated its GWP values for the GHGI to reflect this global agreement and now uses 28x for methane and 265x for nitrous oxide. States, such as New York, and some businesses, have adopted the 20-year

	100-year GWP			20-year GWP		
GHG	AR4	AR5	AR6	AR4	AR5	AR6
Carbon dioxide	1	1**	1	1	1	1
Methane	25	28**	27	72	84	81
Methane (with fossil methane adjustment)	N/A	30	29.8	N/A	85	82.5
Nitrous oxide	298	265**	273	289	264	273

Note: AR is an abbreviation for "Assessment Report" from the IPCC, which has updated GWPs several times in its history. Values (**) are being used by NPC for consistency with U.S. national inventory assumptions.

Table 1-3. *Global Warming Potentials Associated with the Most Common GHGs Reported by the Oil and Gas Industry*

timeframe or provide information on both the 20-year and the 100-year timeframes.

GWP100 AND GWP20

While 100-year GWP is the global standard for comparison of different GHGs as confirmed by the UNFCCC, there is a criticism from some stakeholders that 100 year may underplay the importance of methane emissions to reduce near-term warming, particularly to a view of minimizing global temperature rise in 2050, and that the 20-year GWP better captures this desired outcome. For the typical emissions profile in the oil and gas sector, this would raise the GWP of methane from 28–30 (100-year GWP) to 81–85 (20-year GWP). Directionally, the use of a 20-year GWP would increase the current GHG baseline emissions at the national level in terms of carbon dioxide equivalent, with much of the change being driven by methane-emitting sectors like agriculture, oil and gas, and waste.

The use of a 20-year GWP could influence the relative GHG abatement opportunities selected between sectors but does not influence the actual metric tons of abatement potential for methane or the opportunity set for technologies to reduce emissions. The use of a 20-year GWP would imply a higher starting baseline for emissions but would also lead to much steeper-percentage future reductions from that baseline if sectoral GHG reduction policy is more heavily focused on methane, which is the current focus within U.S. policymaking for the oil and gas sector. While methane reductions in the oil and gas sector are a key focus of current U.S. policy, the use of the 20-year GWP in U.S. policymaking could focus additional policymaking on other methane-emitting sectors like agriculture and waste but would need to be balanced against the need for comparability with GHG reporting in other countries and the potential impacts on current NDCs, which are based on 100-year GWP.

a. GWP Used in Analysis by NPC

For the natural gas supply chain, methane and carbon dioxide are the two primary GHGs, regardless of the metric or timeframe selected. This chapter includes an important discussion about how to reduce both GHGs. When comparisons need to be made that include multiple GHGs, the analysis in this study will use AR5 100-year values, and for methane, these values will not include the fossil methane adjustment. These are made so that analyses can be compared to national baselines (like the GHGI) and the data that EPA submits as part of the UNFCCC process.

4. Performance Metrics

Performance metrics for methane and carbon emissions from oil and gas operations are established to standardize and compare emissions from various operations, regardless of size. Often, there are specific intensity metrics for different parts of the supply chain to account for unique throughput considerations and established goals for companies in that sector. When aligned with life cycle elements, like allocation between multiple products, intensity metrics can allow for benchmarking of the intensity of different operators and products. Some voluntary initiatives and policies like the waste emissions charge in the Inflation Reduction Act of 2022 outline specific performance metrics.

Methane intensity is a normalized measurement of the quantity of methane emitted to the atmosphere, in relation to the total volume of natural gas produced, expressed as percent. In some cases, like for the Natural Gas Sustainability Initiative, energy-based allocations are used to split emissions among the hydrocarbons produced at an asset. Energy-based allocation is an important element in both policy design and metrics that do not necessarily include considerations for all products, which can potentially lead to unintended consequences. For example, a study[55] of emissions intensity in the Eagle Ford shale region found that metrics that did

55 Allen, D.T., Chen, Q., and Dunn, J.B. 2021. "Consistent Metrics Needed for Quantifying Methane Emissions from Upstream Oil and Gas Operations." *Environmental Science & Technology Letters*. 8 (4): 345–49. https://doi.org/10.1021/acs.estlett.0c00907.

not include energy allocation favored dry gas production over associated gas production in the region, even though the emissions intensity of the associated gas with coproduct allocation would be lower.

Segment-intensity metrics are sometimes confused with life cycle assessment models that develop and assign a well-to-gate methane intensity, or loss rate, for the entire natural gas supply chain of interest. There are a variety of different life cycle models that have been developed for U.S. natural gas from the government, private sector, and academic organizations. Life cycle studies and comparisons between models are discussed in detail in Chapter 4.

When investigating the utility of an individual metric, particularly in a system as complex as the U.S. natural gas supply chain, understanding the part of the supply chain covered and additional details is recommended, especially when balancing GHG reduction strategies and policies against the need to maintain infrastructure resiliency until the end of the infrastructure's projected service life. For example, the Oil and Gas Climate Initiative (OGCI) has developed an upstream, methane intensity target of well below 0.2%, comparing the volume of methane emissions from upstream oil and gas operations as a percentage of the volume of the total gas marketed. The OGCI metric includes all upstream emissions from wellhead to point of sale, which includes production-sector emissions and potentially other supply chain elements, depending on the type of operation. Linking the data from the OGCI metric, for example, to a life cycle emissions estimate for a product would require coproduct allocation between the gas, oil, and NGLs produced at a particular asset.

Carbon intensity (CI) is a normalized measure of carbon emissions per barrel of oil equivalent (Boe) produced, often expressed as kg CO_2e/Boe in the production sector. This is a relevant measurement standard for fields producing significant quantities of both oil and natural gas, or for comparing companies that produce varying resources. The denominator is typically related to throughput volumes for other sectors of the natural gas industry, where there is gas transported but not produced at wells.

Intensity metrics require an understanding of total emissions, and most emissions disclosures that include intensity also include absolute emissions in a different line item, which can help to understand trends in overall emissions.

F. GHG Emissions Sources in the Natural Gas Supply Chain

Based on classifications set up by the UNFCCC and adopted by EPA for national inventories, the oil and gas industry has a variety of GHG emissions sources that can be broadly categorized as combustion and noncombustion sources. Under this classification, noncombustion sources include flaring, venting, and fugitive emissions. Examples of combustion sources include engines, turbines, and process heaters. To prioritize sources for further analysis within this study, 2020 source-specific baseline emissions from the GHGI[56] were grouped together with other like sources across the supply chain to prioritize discussion of the largest sources of methane and carbon dioxide emissions in the sector. GHGI emissions categorized under natural gas systems (excluding postmeter emissions), production emissions in petroleum systems, abandoned oil and gas wells, and natural gas combustion for energy use in the supply chain were considered within the scope for this analysis.

Emerging policy may include reductions of emissions in the near term, particularly for methane, and measurement-informed inventories may begin to change the relative size of individual emissions sources in inventories. Specifically, there is concern from some stakeholders that current inventory techniques may underrepresent emissions from intermittent sources and abnormal process emissions. As inventory methodologies are updated over time, the relative importance of different sources may change, but the list of sources included in this analysis would remain the main sources for continued focus in GHG reduction programs.

56 EPA. 2023. "Natural Gas and Petroleum Systems in the GHG Inventory: Additional Information on the 1990-2021 GHG Inventory." April 12, 2023. https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2021-ghg.

Several recent aircraft-based methane measurement research studies[57, 58, 59, 60, 61, 62] have suggested that some sources should be considered as an even higher priority than their inventory-based ranking alone might indicate. All studies listed conclude that, currently, inventory development techniques may underestimate methane emissions for some segments, but the magnitude and cause of underestimates vary between studies. The cause of emissions divergence may be a result of outdated methodologies, equipment malfunctions that are intermittent and difficult to quantify, and temporal variability. Methane emissions associated with tanks, unlit flares, and compressor exhaust have been found to contribute to differences between field measurements and inventories based on activity data and emissions factors.

Facility-specific and basin-specific reconciliation studies are growing but large-scale efforts to drive reconciliation across space and time between field measurements and inventories based on activity data and emissions factors across are needed. Many existing studies only evaluate the production segment. To understand the magnitude and cause of the differences between calculated and measured emissions, subsequent studies may be expanded to include larger percentages of the U.S. natural gas supply chain. Continued incentives may provide roadmaps to achieving expanded reconciliation efforts, such as the DOE funded FOA 2616: Innovative Methane Measurement, Monitoring, and Mitigation Technologies. The current state and development needs for measurement technologies to build more complete methane inventories is a key topic in Chapter 3 in this report. The following sources are focus areas for GHG emissions, based on current public inventories and knowledge.

1. Key Carbon Dioxide Sources

- **Lease and plant fuel:** This category includes combustion emissions from the use of natural gas for energy in production, gathering and boosting, and gas processing activities. In these operations, natural gas may be used for gas compression, to provide power for site operations and drilling equipment, and to provide heat to support separation and to prevent freezing. Specific process units that consume natural gas include drilling operations, heaters, dehydrators, field compressors, and various operations at natural gas processing plants.
- **Pipeline and distribution fuel use:** Pipeline and distribution fuel use volumes are tracked at the national level by the EIA as part of overall estimates for natural gas consumption. This emissions source is primarily combustion for energy use, including for compression, in the transmission and distribution segments of the natural gas supply chain. Natural gas use at LNG liquefaction and regasification facilities are included in EIA numbers for this category at the national level.
- **LNG plant fuel:** This includes combustion emissions for energy use at LNG export facilities. While EIA tracks historic values for this use under pipeline and distribution fuel use, the NPC has broken volumes out individually for this study to be able to match future emissions projections to specific assumptions around the size of LNG export volumes in EIA projections.
- **Flaring:** Flaring is a method to burn excess gas to relieve pressure in upset conditions or

57 Johnson, M.R., Tyner, D.R., and Conrad, B.M. "Origins of Oil and Gas Sector Methane Emissions: On-Site Investigations of Aerial Measured Sources." *Environmental Science & Technology*. January 2023. https://doi.org/10.1021/acs.est.2c07318.

58 Johnson, M.R., Conrad, B.M., Tyner, D.R. "Creating Measurement-Based Oil and Gas Sector Methane Inventories Using Source-Resolved Aerial Surveys." *Nature Communications Earth & Environment*. 4 (139). April 25, 2023. https://doi.org/10.1038/s43247-023-00769-7.

59 Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P., Heat, G.A., Englander, J., Cooley, D., Lyon, D., et al. "Closing the Methane Gap in U.S. Oil and Natural Gas Production Emissions Inventories." *Nature Communications*. 12 (4715). August 5, 2021. https://doi.org/10.1038/s41467-021.

60 Omara, M., Zimmerman, N., Sullivan, M.R., Li, X., Ellis, A., Cesa, R., Subramanian, R., et al. "Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate, *Environmental Science & Technology*. 52, 21, 12915–12925. September 26, 2018. https://doi.org/10.1021/acs.est.8b03535.

61 Cusworth, D.H., Duren, R.M., Thorpe, A.K., Olson-Duvall, W., Heckler, J., Chapman, J.W., Eastwood, M.L., et al. "Intermittency of Large Methane Emitters in the Permian Basin." *Environmental Science & Technology*. 8, 7, 567–573. June 2, 2021. https://doi.org/10.1021/acs.estlett.1c00173.

62 Sherwin, E.D., Rutherford, J.S., Zhang, Z., Chen, Y., Wetherley, E.B., Yakovlev, P.V., Berman E.S.F., et al. "Quantifying Oil and Natural Gas System Emissions Using One Million Aerial Site Measurements." *Nature*. March 2024. 627(8003):328-334. doi: 10.1038/s41586-024-07117-5.

when sending gas to sales is not possible. For this report, flaring is inclusive of both routine and nonroutine volumes. In the United States, flare volumes are primarily concentrated in a few shale oil production regions that are individually tracked within the GHGI data, including the Permian, Bakken, Eagle Ford, and Anadarko basins.

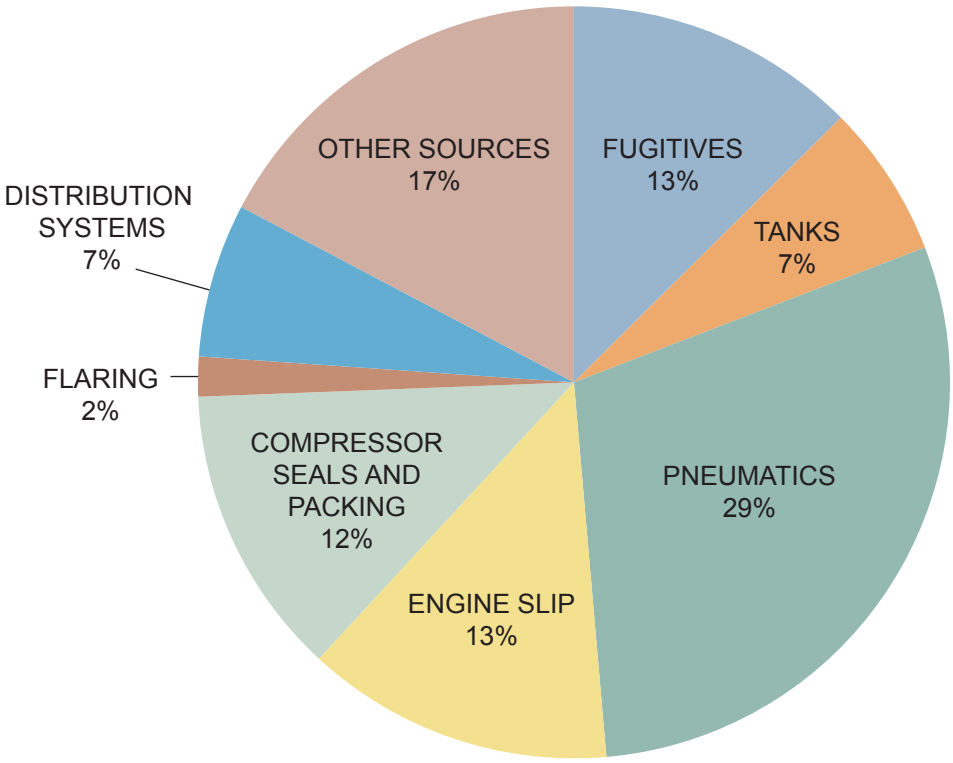
- **Reservoir CO_2 in gas treating and processing:** Natural gas production includes a variety of contaminants that must be separated from the methane component of the gas to meet pipeline specifications for long-distance transmission. The same reservoirs that produce natural gas can also have a naturally occurring carbon dioxide component that is removed at an acid gas removal unit in a gas treating plant. Historically, this carbon dioxide stream has been vented to the atmosphere in most natural gas operations, though it may become a potential focus area for carbon capture and storage. Some operators employ a technique that was first introduced in the 1970s called enhanced oil recovery (EOR), which injects carbon dioxide to stimulate oil production.

2. Key Methane Sources

Key methane sources based on U.S. inventories are described in this section. Methane emissions are a combination of sources that can be classified as venting (intended, direct release of natural gas and associated methane emissions), fugitives (unintentional sources of emissions from components like valves), and incomplete combustion.

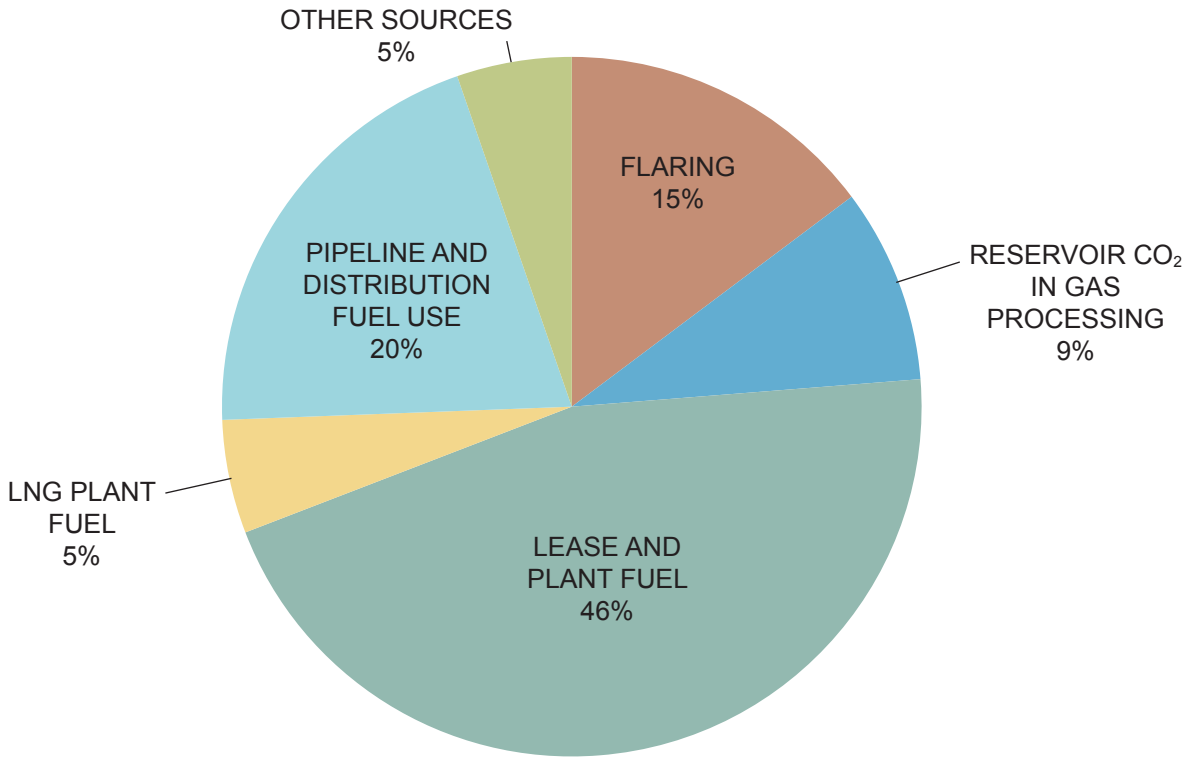
- **Fugitives:** Fugitive emissions are unintentional sources of emissions from components, such as valves and flanges, that are associated with equipment, like separators, across the natural gas supply chain. These are sometimes called equipment leaks. While unintentional, fugitive emissions do occur in the supply chain as no individual components are expected to have a zero-failure rate across many operations. When a leak is detected, components can be repaired or replaced as part of an LDAR program.
- **Tanks:** Storage tanks are used to hold crude oil, produced water, and gas condensate for brief periods to stabilize flow between continuously producing wells and periodic pipeline or trucking transportation. Methane emissions occur mainly from flashing emissions, which are caused by the pressure drop between the tank and the upstream process unit, like a separator. Changes in temperature and fluid levels can also lead to smaller amounts of methane emissions. Based on how EPA classifies emissions in the GHGI, emissions associated with controlled and uncontrolled tanks, including with flares and vapor recovery units, are included in this source category.
- **Pneumatics:** Pneumatics include both controllers that operate process control systems to maintain a process condition such as liquid level, pressure, pressure difference and temperature, and pumps that help to move fluid around sites. Currently, many sites use pressurized natural gas to drive the control and pumping actions, which leads to methane emissions.
- **Engine slip:** Combustion of natural gas occurs in equipment to meet operational energy needs for heat and electricity. Some uncombusted methane will be part of the exhaust stream and is known as engine slip. Much of the aggregate total for engine slip is from internal combustion engines that drive compressors throughout the natural gas supply chain, although the emissions rate varies by type of engine (i.e., lean burn versus rich burn).
- **Flaring:** Similar to engines, flares can have uncombusted methane that is a type of incomplete combustion.
- **Compressor seals and packing:** This category includes emissions associated with venting from rod packing on reciprocating compressors and wet and dry seals on centrifugal compressors.
- **Distribution systems:** Distribution systems deliver natural gas to customers. This category includes a variety of fugitive and venting components that are lumped together for this segment, due to different regulatory frameworks compared to other segments.

Figures 1-24 and 1-25 represent the primary inventoried sources for methane and carbon dioxide emissions sources, respectively, from the natural gas supply chain, as estimated from the GHGI and EIA statistics.



Source: EPA, 2023.

Figure 1-24. *Baseline Methane Proportions from Sources in the Natural Gas Supply Chain in 2020*



Sources: EPA, 2023.

Figure 1-25. *Baseline Carbon Dioxide Proportions from Sources in the Natural Gas Supply Chain in 2020*

3. Marginal Wells

Marginal wells are those that are nearing the end of their economically useful life, but these wells can continue to produce at low rates for many years. For classifying marginal wells, DOE[63] uses a definition from the Internal Revenue Service that defines these as wells producing less than 15 Boe/day (Boe/d) for combined oil and gas production. Marginal wells account for ~79% of current U.S. well counts and 7%–8% of total U.S. oil and gas production.[64]

There has been some debate among stakeholders around the extent to which methane reduction policies should be applied to marginal wells, weighing the potential emissions reduction opportunities at those sites versus their low production rates and potential impacts on small businesses. Federal rules will be discussed in more detail in upcoming sections of this chapter, but as a brief introduction, a 2016 rule from the EPA (New Source Performance Standard OOOOa) exempted marginal wells from LDAR requirements due to concerns about disproportionate compliance costs. The recently finalized updated rules (New Source Performance Standard OOOOb and Emission Guideline OOOOc) from EPA did not include the same explicit exemptions for marginal wells, though states may consider remaining useful life as part of their existing-source rule developments.

Field methane measurement studies have been conducted at marginal well sites and made comparisons between marginal and nonmarginal wells. A study from researchers at the Environmental Defense Fund[65] assigned 37%–75% of national well-site emissions to marginal wells based on an aggregation of off-site measurements from other studies for ~240 low-producing well-site locations. Given the low production rate of these facilities, this finding would imply 6–12 times higher than national average methane intensity and was found to be related to a skewed emissions distribution among marginal wells. The central estimate for methane emissions from low-production well sites, which included but was not limited to marginal wells, in this paper of 4 million metric tons of methane per year is approximately 48% of total methane emissions for oil and natural gas supply chains, as estimated by EPA in the 2021 GHGI.

As part of its research program, DOE also funded a direct measurement study[66] to understand the magnitude and sources of emissions associated with marginal wells that included 524 marginal production sites within the measurement data set. The DOE study estimated a similar percentage of national well-site methane emissions (48%) from marginal well sites. With site access and source-level resolution, the researchers were able to better understand the underlying drivers of emissions, finding that the strongest correlation was with site major equipment count (i.e., complexity of the site) rather than emissions inherent to the wells themselves, which is important to understanding mitigation practices. There can be fixed emissions associated with major equipment (i.e., fugitive components that scale with equipment count) and lower production rate sites have, by definition, a small production volume over which to allocate such emissions, leading to higher GHG intensities. The central estimate for methane emissions from marginal wells in this paper of 1 million metric tons of methane per year is approximately 12% of total methane emissions for oil and natural gas supply chains, as estimated by EPA in the 2021 GHGI.

The Inflation Reduction Act of 2022 included provisions for $700 million dollars in funding for methane mitigation activities at marginal conventional wells, including for technical assistance for GHG reporting, methane monitoring and reduction activities, related community activities, and permanently plugging and abandoning wells on nonfederal land through fiscal year 2028. The initial funding opportunity from EPA and DOE for

63 EIA. "U.S. Oil and Natural Gas Wells by Production Rate". 2023. https://www.eia.gov/petroleum/wells/.

64 Bowers, Richard. 2022. "Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells." U.S. Department of Energy. https://doi.org/10.2172/1865859.

65 Omara, M., Zavala-Araiza, D., Lyon, D.R., Hmiel, B., Roberts, K.A., and Hamburg, S.P. 2022. "Methane Emissions from U.S. Low Production Oil and Natural Gas Well Sites." *Nature Communications.* 13 (1). https://doi.org/10.1038/s41467-022-29709-3.

66 Bowers, Richard. 2022. "Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells." U.S. Department of Energy. https://doi.org/10.2172/1865859.

the program[67] includes up to $350 million targeted at plugging, abandonment, and restoration activities for marginal conventional wells on nonfederal lands, with a state-by-state allocation formula based on marginal well count and does not include federal or Tribal lands. Fourteen states have received conditional funding commitments under this program as of the end of 2023, and more grant opportunities are expected to be released by EPA and DOE in future years for further distribution to operators or consortia. For operators where upcoming methane regulations may make wells uneconomic, this funding announcement could offer an opportunity for financial assistance with the costs of plugging and abandonment activities.

Given the level of remaining funding under the Inflation Reduction Act that is specified for emissions reporting, monitoring, and reduction activities at marginal wells, there is an important opportunity for public and private partnership to better understand and reduce emissions at these locations. Scientifically, measurement studies cited in previous paragraphs have included less than 0.1% of the U.S. marginal well population, which could potentially be expanded through the use of advanced screening technologies, such as aircraft, to improve coverage for this subset of production. For approaches like aircraft monitoring, where small operator data may be collected during flights for other clients, there may be opportunities for vendors to provide emissions data information to smaller operators. Relevant state oil and gas associations may have a role in facilitating such data sharing.

Funding for technical assistance on emissions reporting in the Inflation Reduction Act is likely to help with emissions inventory generation activities at marginal wells. The U.S. GHGRP includes GHG reporting for ~51% of the total well count for the United States and given the basin-level reporting threshold of 25,000 metric tons of carbon dioxide equivalent per year in annual emissions, wells that are not subject to GHG reporting requirements are likely to be primarily smaller or marginal producers. For emissions reduction project funding, administrative elements for program applications and funding should be minimized, while ensuring that funding is used for methane reduction projects to increase accessibility for smaller operators. DOE should consider models that facilitate access to funds and reduce administrative processes, like regional consortia applying for and distributing funding to smaller operators.

Marginal wells are not uniquely operated by smaller and less capitalized operators. Regardless of operator size, the wells are typically associated with lower cash flows compared to newer wells and operations. Thus, there is some concern that costs associated with upcoming regulations could disproportionately impact marginal wells and lead to situations where continued production would be uneconomic. State and federal tax codes in the U.S. have historically recognized the economic circumstance for marginal wells and provided incentives for their continued operation due to their value for energy security, particularly in low-price environments when investment in newer energy supplies typically declines. Similar tax treatments and policies for marginal wells, such as deduction of GHG reduction investments from state severance taxes or federal royalties, could accelerate reduction programs for these types of assets.

Besides plugging and abandonment, there are other options for wells at the end of their useful life for oil and natural gas production. For example, while the study did not evaluate the repurposing of wells for alternative purposes other than oil and gas production, the study team recognizes the importance of evaluating and addressing regulatory fixes to encourage repurposing wells in line with environmental protection and carbon reduction.

FINDING 9: **Specific funding allocations for methane reporting, monitoring, and emissions reductions at marginal conventional wells in the Inflation Reduction Act offer a unique and timely opportunity for public and private partnerships to better understand emissions and complete emissions reduction projects at this subset of U.S. national production.**

67 DOE. "Funding Notice: IRA: Mitigating Emissions from Marginal Conventional Wells." December 15, 2023. https://www.energy.gov/fecm/funding-notice-ira-mitigating-emissions-marginal-conventional-wells.

FINDING 10: Field measurement studies of marginal wells that have been used in rule making have included small sample sizes, relative to the national population of marginal wells.

RECOMMENDATION 1: *The NPC recommends that the DOE and state oil and gas associations undertake additional methane measurement studies with increased sample sizes beyond 1,500 wells, pro rata in multiple basins, and including operators input into study design.*

FINDING 11: Marginal wells have economic situations that require unique policies to enable GHG reductions.

RECOMMENDATION 2: *The NPC recommends state and federal governments review options for marginal wells, including deduction of GHG emissions reduction investments from state or federal tax or royalty obligations.*

4. Less Capitalized Operator Workshops

As part of this study, the NPC conducted four "Less Capitalized Operator" (LCO) workshops in Houston, Midland, Denver, and Pittsburgh. LCO was loosely defined. The invitations were directed to companies with generally less than $2 billion market capitalization value and with production ranging from less than 1,000 Boe/d to more than 50,000 Boe/d. More than 70 companies attended the workshops. Some companies had one employee while others employed a few hundred. These smaller operators shared operational practices and their feedback on challenges and opportunities for reducing GHG emissions in the natural gas supply chain. The themes of findings from LCO participants in these workshops included Findings 12–15.

FINDING 12: Some leak detection and repair programs can be executed at low cost to materially reduce methane emissions. Less Capitalized Operators shared success cases of implementing audio, visual, olfactory, and practical advanced technology applications.

FINDING 13: Many Less Capitalized Operators are concerned about emissions and strive to comply with emerging federal regulations but do not have the organizational structure and expertise to interpret complex, sometimes conflicting requirements.

FINDING 14: Less Capitalized Operators may not have the staff to address GHG emissions reduction opportunities through emissions measurement tools, facility modifications, operating procedure changes, or evaluation and implementation of new technology.

FINDING 15: Several participants highlighted the potential for upstream producers and midstream companies, along with regulators, to investigate ways to jointly address GHG emissions by looking more holistically at the entire natural gas supply chain.

G. Reductions Opportunities

This section summarizes control technologies that are available for use in the natural gas sector to reduce emissions. For many sources, there are multiple potential options that an operator could consider for reducing emissions from the same source. Decisions for individual assets would rely on additional factors beyond availability, including regulatory requirements, relative cost effectiveness, and site-specific implementation issues.

1. Control Technologies for Methane

Using natural gas to actuate pneumatic devices, control valves, and pressure regulators is common in the oil and gas industry, especially in remote locations where electricity isn't readily available. These pneumatic devices are designed to use the mechanical energy available as pressurized gas to physically actuate the device and then vent the gas to the atmosphere once actuated. Historically there have been multiple options to reduce emissions from pneumatic devices, including the

retrofitting of high bleed controllers to reduce venting rates, conversions from natural gas to compressed air for the motive fluid, and routing of pneumatic emissions to an on-site control device, like a heater or flare. Pneumatic controllers are currently the largest source of methane emissions in the sector in the GHGI, but recently finalized regulations from EPA may drive new and existing operations to install air compressors, convert to electric controllers, or deploy other nonemitting technologies.

For tanks, the first upstream federal regulation to require emissions controls from many new and modified sources occurred in 2011 under the New Source Performance Standard (NSPS) OOOO. Options to reduce emissions associated with tanks include vapor recovery units, which compress tank vapors and redirect to sales or other on-site use, vapor recovery towers that act as surge vessels to reduce the pressure drop between a separator and the tank, and combustive control devices, like flares. Some studies have indicated higher-than-expected methane emissions from some tanks with these controls installed due to component failures at thief hatches or other pressure relief devices. LDAR programs, or audio visual olfactory (AVO) inspections, by operators can help to ensure proper functioning of this equipment to minimize emissions. Installation of pressure indicators has become an option to monitor tank conditions that could result in lifting of thief hatches. Historically, storage tanks at oil and gas sites were not able to handle pressures exceeding 1 or 2 pounds per square inch (psi). Thief hatches were installed as both devices to allow for access to monitor levels or test fluids and as pressure protection devices for the tank. In some cases, operators have implemented tankless facilities (vessels intended to temporarily hold volumes at higher pressures than traditional atmospheric tanks and thus do not require thief hatches) or reduced the number of storage tanks across an entire field. Challenges still exist in vapor recovery unit implementation where strict oxygen limits are in place for gathering pipelines from gas production wells due to corrosion concerns. Technologies exist for oxygen removal to address contamination issues but add additional cost to retrofitting existing operations. Recently finalized EPA rules include additional control technology and inspection requirements for storage tanks.

For fugitives and equipment leaks, LDAR programs are the most common emissions reduction option. Emissions detection can occur both from instrumented detection from approaches like optical gas imaging (OGI) and EPA Method 21 (Determination of Volatile Compound Leaks) or from AVO observations from operators. Emerging alternative technologies, particularly those with a low minimum detection limit, are beginning to be proven as highly effective in identifying emissions and may represent a more cost-effective and efficient approach to reducing methane emissions. Recently finalized EPA rules include requirements for implementing LDAR programs, with quarterly OGI as the baseline technology requirement for tank batteries and compressor stations. Modeling for LDAR programs[68] has typically shown diminishing emissions returns for each additional LDAR survey conducted, meaning that increasing frequency beyond a certain point may have limited additional associated emissions reductions, while increasing cost. For marginal producing wells, the costs of an instrumented LDAR program can be a significant portion of the annual revenue for the well. Policies like the Inflation Reduction Act of 2022 include funding for implementation at these types of sites, though the ability of small operators to access such funding is to be determined. Proposed rules from PHMSA include LDAR requirements for other types of infrastructure, like pipelines and distribution systems.

Engine slip has been shown to be a significant source of methane emissions from compressor engines, although it varies by the type of engine. Lean-burn engines are common throughout the oil and natural gas supply chain since they have lower nitrogen oxide (NO_x) emissions than other options like rich-burn engines, underscoring potential trade-offs between policies concerned with historic management of criteria pollutants and GHG reduction objectives. Studies and stack testing results have typically shown that existing lean-burn engines have the highest methane slip rate, but they have been a historic choice in the sector to help comply with local air quality regulations. Current lower-methane emissions options

68 GTI for Environmental Defense Fund. "Evaluation of Emerging Methane Detection Methods." 2021. https://www.gti.energy/wp-content/uploads/2022/03/Evaluation-of-Emerging-Methane-Detection-Methods_Dec2021.pdf.

include rich-burn engines or compressor electrification. Compressor electrification requires the ability to access reliable and low-emissions power and the ability to permit and build the associated electric infrastructure to power the compressor. Permitting reform would be essential to assist with the buildout of electrical infrastructure for an accessible grid as many production operations are in more remote areas where access to power can be limited by existing transmission or generation capacity. The DOE is funding early phase research under the ARPA-E Reducing Emissions of Methane Every Day of the Year (REMEDY)[69] program to develop retrofit options to reduce methane slip in these applications, including technologies that would act as a postcombustion catalyst to reduce methane emissions in exhaust gas or other techniques to replace compressor internals to reduce methane slip generation.

Compressor seals and packing have a variety of control options to reduce emissions and depend on the type of equipment present on a site. For wet seal centrifugal compressors, methane emissions can be reduced by capturing methane emissions from the circulating seal oil at the seal pot or converting to a dry seal configuration. For reciprocating compressors, which are more common in U.S. onshore applications, replacement of rod packing at set intervals (planned maintenance) or based on inspection results can reduce emissions. Recently finalized EPA rules include requirements to reduce emissions from both centrifugal and reciprocating compressors.

For flaring, the largest emissions reductions for both methane and carbon dioxide are associated with reducing the volume of gas flared at a site. For associated gas production, this would include ensuring that sufficient takeaway capacity is available to gather, process, and transport the natural gas. In the last few years, takeaway capacity has not been sufficiently available in several shale oil production regions. For other sources of flaring, improving operational reliability can reduce safety-related flaring volumes over time. To reduce methane emissions from the flaring source, there are a variety of technologies that can be installed to ensure that the flare remains lit and operating within design ranges to ensure good combustion efficiency. Recently finalized EPA rules include limits on associated gas flaring and the use of technologies to ensure flares are operating at designed efficiency.

During the LCO workshops, several companies shared a common experience where there were challenges in collaboration between upstream producers and midstream providers. In the LCO experience, unplanned downtime at midstream facilities from reliability or other concerns has led to flaring, as there is often only one marketing route for natural gas production. In practice, this flaring often occurs at distributed upstream assets versus at the processing plant or centralized facility with the unplanned downtime. LCOs expressed concerns that policies such as the methane waste emissions charge, which is discussed in detail in upcoming sections on federal regulation, could lead to even more complex situations for where flaring occurs during upset conditions, as some gathering contracts were developed before such programs were contemplated and the upstream and midstream contractual interests may not be fully aligned on this topic in current contracts. Reliability improvements and upgrades at midstream infrastructure would have benefits to upstream producers, and there is the potential for contracting models that could incentivize such investments to the benefit of both parties and reduce overall GHG emissions in that supply chain. Several LCO workshop participants pointed to economic value both for recovered gas and the reduction of the methane waste emissions charge for an operator.

In distribution systems or other supply chain segments with pipelines, emissions associated with maintenance blowdowns can be avoided by routing gas to low-pressure systems, through permanent or temporary piping; or the use of portable compressors to divert most of the remaining gas into the receiving line. Best practices, including testing and repairing pressure safety valves, performing valve leak repair during pipeline replacements, recovering gas from pigging operations, blowdown capture, and using pipeline pump-down techniques to depressurize before maintenance, should also be considered to reduce methane emissions.

69 REMEDY– Reducing Emissions of Methane Every Day of the Year. Program released April 8, 2021. https://arpa-e.energy.gov/technologies/programs/remedy.

Innovative facility designs hold potential to reduce total equipment counts associated with a development, likely reducing the associated equipment leaks and fugitive emissions. This includes increased centralization of facility designs to eliminate the amount of equipment, as in tankless facilities. This also includes the incorporation of inherently lower-emitting technologies in new facility designs, for example selecting dry seals versus wet seal technology for new centrifugal compressors.

FINDINGS 16-20:

- **16: The largest current sources of methane emissions in inventories are included in the suite of emerging federal regulations. Alternative technologies to identify intermittent emissions could enhance the emissions reduction potential of source-specific abatement requirements.**
- **17: Technology costs and frequency of deployment need to be workable for marginal wells and smaller producers. Funding mechanisms in the Inflation Reduction Act have become available through DOE and EPA, but simple access is necessary to drive future GHG reduction for this subset of producers.**
- **18: Innovative facility designs, like tankless facilities and new equipment selection, can eliminate potential emissions sources and reduce GHG emissions.**
- **19: The U.S. natural gas supply chain is large and complex. There are opportunities for companies of all sizes to reduce flaring and methane emissions. Methods for monetization of flared or vented volumes will increasingly include both realized gas prices and avoided fees.**
- **20: In some cases, interests of upstream and midstream companies are not contractually aligned to reduce flaring and methane emissions across operations. Better collaboration across the upstream and midstream segments would enable additional net emissions reductions.**

RECOMMENDATION 3: ***The NPC recommends that upstream and midstream companies consider revising contracts to ensure financial alignment and encourage the development of adequate offtake capacity and implementation of reliability improvements to help reduce planned and unplanned flaring.***

2. Control Technologies for Carbon Dioxide

More than 70% of the carbon dioxide emissions within the scope of this study are associated with natural gas combustion for energy use for compression, heat, and power applications throughout the natural gas supply chain. Current strategies to reduce carbon dioxide emissions from energy use range from energy efficiency improvements like upgrading to newer compressors to electrification strategies that can reduce direct emissions. Some applications like process heat are quite challenging to electrify with current technologies, and the net GHG reductions associated with electrification depends on the CI of the associated grid connections. As stated in the previous section, electrification for the production and gathering and boosting sections of the supply chain are dependent on the ability to access economic, reliable, and lower-emissions power and the ability to permit and build the associated electric infrastructure. Permitting reform is going to be essential to assist with the buildout of electrical infrastructure for an accessible grid where transmission or generation capacities are lacking and access to power can be limited.

Beyond electrification and energy efficiency improvements, future technologies to capture carbon dioxide emissions from larger point sources or to substitute with a lower CI energy source, like low carbon intensity hydrogen or carbon capture and storage (CCS), could provide additional GHG reduction levers associated with field energy use.

Reservoir carbon dioxide represents ~9% of carbon dioxide emissions within the scope of this study. The past NPC Dual Challenge Study[70]

70 National Petroleum Council. 2019. "Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage." https://dualchallenge.npc.org/.

identified this source of carbon dioxide as a promising candidate for CCS activities due to the higher concentration of carbon dioxide in the stream, compared to other applications like natural gas-fired power generation. There are several active projects that recycle carbon dioxide emissions from gas processing activities for use in EOR and several proposed projects that would use this type of carbon dioxide point source for EOR or other storage applications, pending appropriate permits and project approvals.

These emissions reduction options require both continued technology development and the ability to permit and install infrastructure, like carbon dioxide pipelines and injection sites, to become feasible. Successful implementation will also require incentives to develop as well as removing regulatory hurdles through permitting reform to achieve a timely buildout of projects. Both hydrogen and CCS buildout face significant cost, supply chain and permitting roadblocks that will require policy action to achieve the desired goals.

II. POLICIES AND VOLUNTARY INITIATIVES IN THE UNITED STATES

Several different policy approaches can be employed to reduce or offset GHG emissions. Common mechanisms that can be applied to the natural gas supply chain include technology investments, market-based mechanisms, and regulation. Each is briefly described in this section.

Technology investments help to develop and deploy alternative technologies that have lower GHG emissions in specific applications. Examples include research and development programs, like the DOE's Advanced Research Projects Agency-Energy (ARPA-E) program that seeks to advance high-potential early phase technologies that are too early for private sector investment and the DOE Seeding Critical Advanced for Leading Energy technologies with Untapped Potential (SCALEUP) program that helps to commercialize promising technologies. Technology investments can be focused on developing new approaches to reducing emissions or reducing the cost of deployments, which can help to incentivize wider adoption. Successful technology investment programs tend to take a portfolio, or basket, approach, where multiple early phase approaches are funded, since not all concepts will turn into commercially viable products.

Market-based mechanisms seek to place a value on an environmental externality, like GHG emissions, to create financial incentives for emissions reductions that can be included in investment decisions. This type of policy approach relies on robust and consistent measurement, monitoring, reporting, and verification (MMRV) frameworks to create trust and transparency within the market. Market-based approaches include tax credits for GHG abatement projects like 45Q for CCS in the United States, premiums for low-emissions-intensity natural gas production, low-interest financing to support GHG reduction projects, or carbon pricing models. Carbon pricing can be implemented with either a cap-and-trade model (where allowable emissions levels decrease over time and the relative scarcity drives the market price) or a fee-based model where prices increase on a transparent schedule.

Regulation includes rules at the state or federal level that put specific requirements to report or reduce emissions on operations, generally in a specific sector. For the natural gas supply chain in the United States, emerging regulations have often taken the form of command-and-control programs that require the installation of specific emissions control technologies at sources of GHG emissions or defined frequencies for LDAR programs. Command-and-control programs have been the most common administrative policy tool for implementation but are often criticized by affected industries due to the lack of flexibility in determining the most cost-effective way to meet program goals. Other regulatory models can include programs that establish GHG emissions limits or intensity performance requirements for different sectors, which differ from market-based mechanisms in that they lack a price signal to drive decision-making, but still offer increased flexibility when compared to command-and-control programs.

It should be noted that regulation does not always refer to the implementation of new rules or requirements in a sector. Good policy would include a periodic revisiting of regulatory requirements to examine their effectiveness and updates

to regulatory environments based on current needs, examination of unintended consequences, and advancements in technology. Well-designed regulatory reform could enable additional GHG emissions reductions in sectors where regulatory requirements, such as permitting or specific technology deployment requirements, are restricting innovation or the ability to complete projects.

Upcoming sections discuss examples at the state and federal level for which different types of policies have been utilized in aspects of the natural gas supply chain. It should be noted that both market-based mechanisms and regulations require continued advancements in technology options and cost to successfully reduce GHG emissions while ensuring affordability and reliability of natural gas supply.

A. State Policy

There is variation in state-level policy around natural gas and policies to reduce GHG emissions from the natural gas supply chain. As shown in Figure 1-26, natural gas production and consumption is not uniform across states, with ~70% of natural gas production occurring in five states (Texas, Pennsylvania, Louisiana, West Virginia, and Oklahoma) in 2021. Some states, like California, New York, and Florida, are large aggregate consumers of natural gas but have relatively small overall production. State-level opportunities for GHG reduction from the natural gas supply chain will depend on the relative size of supply chain stages in that state.

Several states have developed their own GHG reduction plans for oil and gas operations that are separate from federal efforts. Some of these state-identified reduction opportunities have been included in recent federal regulatory actions. Depending on the relative regulatory authority for agencies in the state and other drivers, like federal air quality standard compliance, state-level policies have taken a variety of forms, including volatile organic compound controls (e.g., Colorado, New Mexico), resource conservation requirements (e.g., New Mexico, Alaska), and direct methane controls (e.g., Colorado, California). State permitting requirements (e.g., Texas) can also include specific mitigation actions like LDAR programs that are embedded in permit requirements and operational emissions limits.

States with more limited oil and natural gas supply chain stages may simply follow federal policy and not adopt their own specific regulations for the sector. While past federal policy in the United States has not included specific GHG requirements for the natural gas supply chain, there has been indirect influence on state programs via air quality regulations associated with State Implementation Plans (SIP) related to nonattainment of National Ambient Air Quality Standards (NAAQS). For example, SIPs targeting volatile organic compound (VOC) emissions reduction have a methane emissions reduction cobenefit.

The following section discusses approaches that individual states have taken to reduce GHG emissions from natural gas supply chains, with a focus on regulations in oil and gas production sector activities (see Table 1-4 for highlights). This is not meant to be comprehensive of all state programs but focuses on a few states with different existing regulatory approaches in the production sector.

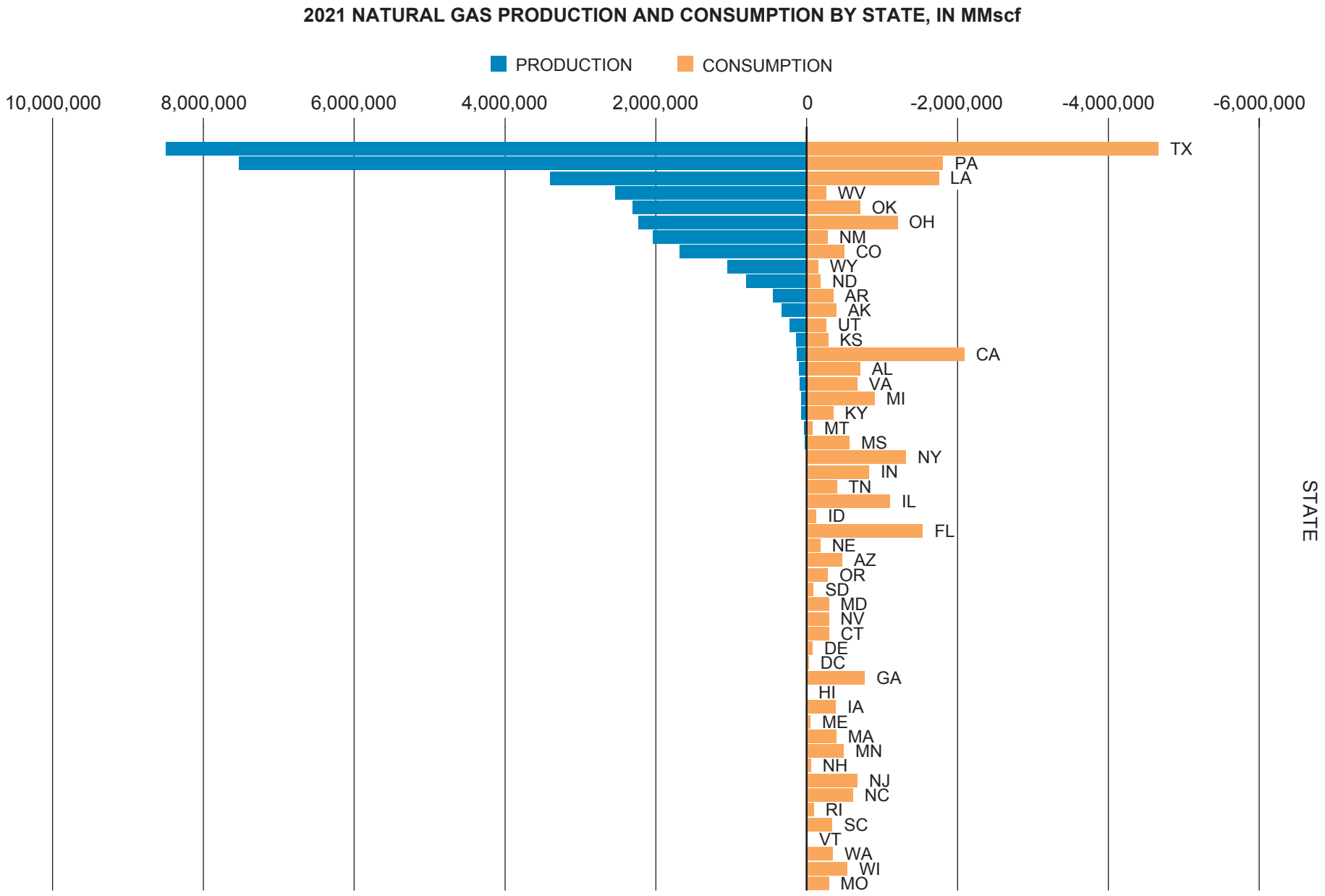
1. New Mexico

As of 2022, New Mexico is the seventh-largest producer of natural gas and second-largest producer of crude oil in the United States.[71] Natural gas produced in New Mexico is concentrated primarily in two basins: dry gas from San Juan Basin in the northwest and predominantly associated gas in the Permian Basin in the southeast.

In January 2019, New Mexico Governor Michelle Lujan-Grisham issued an executive order[72] committing the state to support the 2015 Paris Agreement goals, join the U.S. Climate Alliance, and target statewide GHG emissions reductions of at least 45% by 2030 versus 2005 levels. The executive order also created a Climate Change Task Force, cochaired by the secretaries

71 EIA. "New Mexico State Profile and Energy Estimates." EIA State Data and Analysis. May 18, 2023. https://www.eia.gov/state/?sid=NM.

72 Executive Branch of the State of New Mexico. "Executive Order 2019-003: Executive Order on Addressing Climate Change and Energy Waste Prevention." January 29, 2019. https://www.governor.state.nm.us/wp-content/uploads/2019/01/EO_2019-003.pdf.



Source: EIA, 2024, "Natural Gas Dry Production" and EIA, 2024, "Natural Gas by End Use."

Figure 1-26. *State-Level Natural Gas Production and Consumption Estimates for 2021*

CASE STUDY: PERMITTING AN INNOVATIVE FLARING REDUCTION APPROACH IN NEW MEXICO

Temporary downstream market interruptions, such as the shutdown of facilities and pipelines for maintenance and repair, can affect the ability to transport gas to processing facilities. Upstream producers may then need to decide between shutting in producing oil wells or flaring associated gas during the interruption period. The State of New Mexico's methane rules require that by the end of 2026, oil and gas operators must capture at least 98% of natural gas produced.

With the gas capture requirements, a New Mexico producer evaluated multiple alternative options to flaring during downstream market interruptions and decided to trial Closed Loop Gas Capture (CLGC), which diverts gas from compressor stations or gas gathering systems to a pipeline to be metered and injected into a nearby well.

Deploying this concept required not only implementing a new technical procedure, but also working with the State of New Mexico to develop a regulatory framework for permitting CLGC projects. Before approaching the regulatory agencies in New Mexico to propose the project, the company selected a well that was suitable for injection based on certain reservoir, geologic, structural, and land ownership parameters. The New Mexico Oil Conservation Division approved the application of CLGC as a pilot project through an administrative hearing. The pilot project was designed to allow both the company and the agency to collect and analyze data regarding this type of injection. Following a successful pilot test of the project, CLGC became an option for other operating areas within the region.

of the Energy, Minerals and Natural Resources Department (EMNRD) and the Environment Department (NMED), charged with enacting a strategy to achieve mandated reductions. This resulted in regulations enacted by both agencies. In May 2021, EMNRD enacted two rules through the Oil Conservation Division that restricted the routine flaring and venting of natural gas and established a 98% gas capture requirement by 2026 for both production and midstream operations. In August 2022, NMED enacted the Ozone Precursor Rule establishing NO_x and VOC emissions limits and work-practice standards.

EMNRD requires annual reporting of each operator's gas capture percentage, while NMED requires periodic reporting of GHG emissions according to EPA's GHGRP. The Climate Change Task Force must also produce an annual report in the fall of each year describing the progress achieved against the state's climate goals and provide additional recommendations.

In the process of developing the draft rules, NMED and EMNRD convened a technical Methane Advisory Panel (MAP) comprised of 27 members representing a diverse set of technical stakeholders that included large and small operators, environmental organizations, service providers, and Tribal representatives. The MAP collaborated with NMED and EMNRD over a two-year period and was charged with informing the state on technical topics related to methane reductions in the oil and gas industry.

2. Colorado

In 2022, Colorado was the fifth-largest crude oil producing and eighth-largest natural gas-producing state.[73] Natural gas production in the state is primarily from associated gas from the Denver-Julesburg Basin in northeastern Colorado and dry gas production from the Piceance Basin on Colorado's western slope.

In 2019, Colorado's legislature passed House Bill 19-1261, the Climate Action Plan to Reduce Pollution, which includes targets for reduction of statewide GHG emissions of 26% by 2025, 50% by 2030, and 90% by 2050 from 2005 levels. Planned progress to meet these targets is outlined in Colorado's *Greenhouse Gas Pollution Reduction Roadmap*, which identifies pathways

73 EIA. "Colorado State Profile and Energy Estimates" EIA State Data and Analysis. May 18, 2023. https://www.eia.gov/state/?sid=CO.

State	GHG Reduction Goal(s)	Driving Mechanism	Primary Agencies Involved
NM	• State: 45% by 2030 compared to 2005 levels	Executive Order (2019)	Energy, Minerals, and Natural Resources (EMNRD) and New Mexico Environment (NMED) departments
CO	• State: 26% in 2025, 50% by 2030, and 90% by 2050 from 2005 levels • O&G: 36% by 2025 and 60% by 2030 from 2005 levels	State legislation House Bill 19-1261 (2019)	Air Quality Control Commission (AQCC) and Energy and Carbon Management Commission (ECMC)
PA	• State: 26% by 2025, and 80% by 2050 from 2005 levels	Executive Order (2019)	Department of Environmental Protection (DEP)
CA	• State: 48% by 2030, compared to 1990 levels and 85% by 2045 • State: 2030 target to reduce methane emissions by 40% by 2030	Global Warming Solutions Act (2006) with 2022 Scoping Plan	California Air Resources Board (CARB)

Table 1-4. *Examples of State-Level Policies Covered in This Section*

to meet the state's GHG emissions targets. The sectoral targets for reductions in the oil and gas industry are 36% by 2025 and 60% by 2030. In Colorado, the Air Quality Control Commission (AQCC) is charged with promulgating rules and regulations consistent with legislative directives. In December 2021, the AQCC undertook a rulemaking action to adopt a GHG intensity program designed to achieve GHG reduction targets for the oil and gas industry. AQCC Regulation No. 7 details the specific intensity targets and emissions inventory requirements for operators in the state. In 2023, the AQCC adopted GHG verification regulations to track progress toward meeting the state's greenhouse gas reduction goals and to evaluate compliance with the GHG intensity program.

Similarly, the Energy and Carbon Management Commission (ECMC), formerly known as the Colorado Oil and Gas Conservation Commission, has promulgated rules to require cumulative impacts of oil and gas development be evaluated and addressed before new well permits can be issued and to prohibit routine flaring.

Similar to the MAP process in New Mexico, changes to regulations in Colorado are typically preceded by a multistakeholder input process that includes operators, environmental groups, and interested community members to try to develop regulations that are supported by different groups.

3. Pennsylvania

Based on EIA data for 2022, Pennsylvania is the second-largest producer of natural gas in the United States.[74] Pennsylvania has two distinct populations of natural gas wells, including ~68,000 legacy marginal conventional wells from more than 100 years of production activity in the state and a smaller number of horizontal, unconventional wells in the Marcellus and Utica shale plays that account for the majority of production.

In January 2019, Pennsylvania Governor Tom Wolfe issued executive order 2019-01, which established a statewide climate goal of net GHG emissions reductions from 2005 levels of 26% by 2025 and 80% by 2050.

Emissions from the production of natural gas are primarily regulated through the requirement for new and modified sources to obtain a General Operating Permit 5A (GP-5A). Established in 2018, GP-5A sets emissions limits work-practice standards for VOCs (and methane as a cobenefit) and other criteria pollutants, including glycol dehydration units, reciprocating compressors, storage vessels, pneumatic controllers and pumps, pigging operations, and liquids unloading.

74 EIA. "Pennsylvania State Profile and Energy Estimates" EIA State Data and Analysis. December 21, 2023. https://www.eia.gov/state/analysis.php?sid=PA.

The Pennsylvania Department of Environmental Protection is required by the Climate Change Act of 2008 to compile an annual inventory of GHGs emitted in the state by major sector, establish trends, and track progress against the 2025 and 2050 reduction goals. The most recent report,[75] released in October 2022 (based on 2019 data), indicated a net GHG reduction of 18% compared to 2005 levels.

4. California

California is different from other states used as examples since it is a net importer of natural gas, as shown in Figure 1-26, and relies on natural gas produced in other states and Canada for 90% or more of its in-state use.[76]

With the Global Warming Solutions Act of 2006, and a series of follow-on legislative and regulatory actions, California has established its own GHG reduction targets and state-level goals. The 2022 update to the Scoping Plan for the state[77] includes a scenario to reduce GHG emissions by 48% by 2030, compared to a 1990 baseline, and 85% by 2045. The state also has a strategy for emissions reduction of short-lived climate pollutants, which includes a 2030 target to reduce methane and hydrofluorocarbon emissions by 40% by 2030. In 2020, emissions from oil and gas production and natural gas transmission and distribution were ~4.6% of statewide GHG emissions.

The California Air Resources Board (CARB) has specific regulations for GHG reporting and command-and-control regulations around specific source performance requirements across in-state oil and natural gas supply chain emissions, including specific oil- and gas-related methane regulations. California also has a cap-and-trade program that includes oil and gas production facilities within the program boundaries, where allowances are allocated and disseminated through auctions held by CARB.

5. Overall Variation in State-Level Regulations

Many states have regulations with limitations on flaring and venting activities or requirements to perform LDAR activities to manage fugitive emissions. These have not been developed and deployed in a consistent manner. The Office of Fossil Energy and Carbon Management in DOE developed a report that overviewed flaring and venting policies[78] at the state level in 2019. The report found that all major producing states had regulations preventing waste of natural gas but different specific approaches on exact requirements for flaring and venting volumes.

States can have very different approaches for the type of technology that can be used in LDAR inspections. For example, California has a long-standing requirement for operators to utilize Method 21, also known as sniffing, for LDAR surveys in oil and gas operations. By contrast, Colorado LDAR regulations included the use of OGI and developed an equivalency pathway for certifying new technologies for use in their LDAR program. Three technology vendors have been approved under this equivalency pathway.

Prior to the suite of federal methane reduction regulations that will be discussed in detail in the next section, oil- and gas-producing states had been administering environmental programs that directly, or indirectly through VOC rules, included requirements for methane management. The variety of state programs offered examples for federal policy design, prior to nationwide regulations on the topic.

The formation of multistakeholder groups as part of the regulatory development process that more directly included the regulated entities, regulators, and interested additional parties could be

75 Pennsylvania Department of Environmental Protection. 2022. "Pennsylvania Greenhouse Gas Inventory Report." October 6, 2022. https://files.dep.state.pa.us/Energy/Office%20of%20Energy%20and%20Technology/OETDPortalFiles/ClimateChange/PennsylvaniaGreenhouseGasInventory2022.pdf.

76 California Energy Commission. "Supply and Demand of Natural Gas in California." n.d. https://www.energy.ca.gov/data-reports/energy-almanac/californias-natural-gas-market/supply-and-demand-natural-gas-california.

77 California Air Resources Board. "2022 Scoping Plan for Achieving Carbon Neutrality." November 16, 2022. https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp_1.pdf.

78 DOE. "Natural Gas Flaring and Venting: State and Federal Regulatory Overview, Trends, and Impacts." 2019. https://www.energy.gov/fecm/articles/natural-gas-flaring-and-venting-regulations-report.

a way to improve feasibility of proposed regulations in other jurisdictions. The process gives an early opportunity to understand trade-offs and opens the door to collaboration on how to best achieve common GHG reduction goals through advisory boards, and to create regulations that can best adapt to new technologies. It should be noted that the final product developed by agencies may not necessarily be representative of all stakeholder views in the process, even if they are developed with input from multiple parties.

RECOMMENDATION 4: *The NPC recommends that future federal and state regulations include a more robust, up-front multistakeholder engagement to improve the feasibility of future GHG emissions reduction policies and promote collaboration on how to best achieve common goals.*

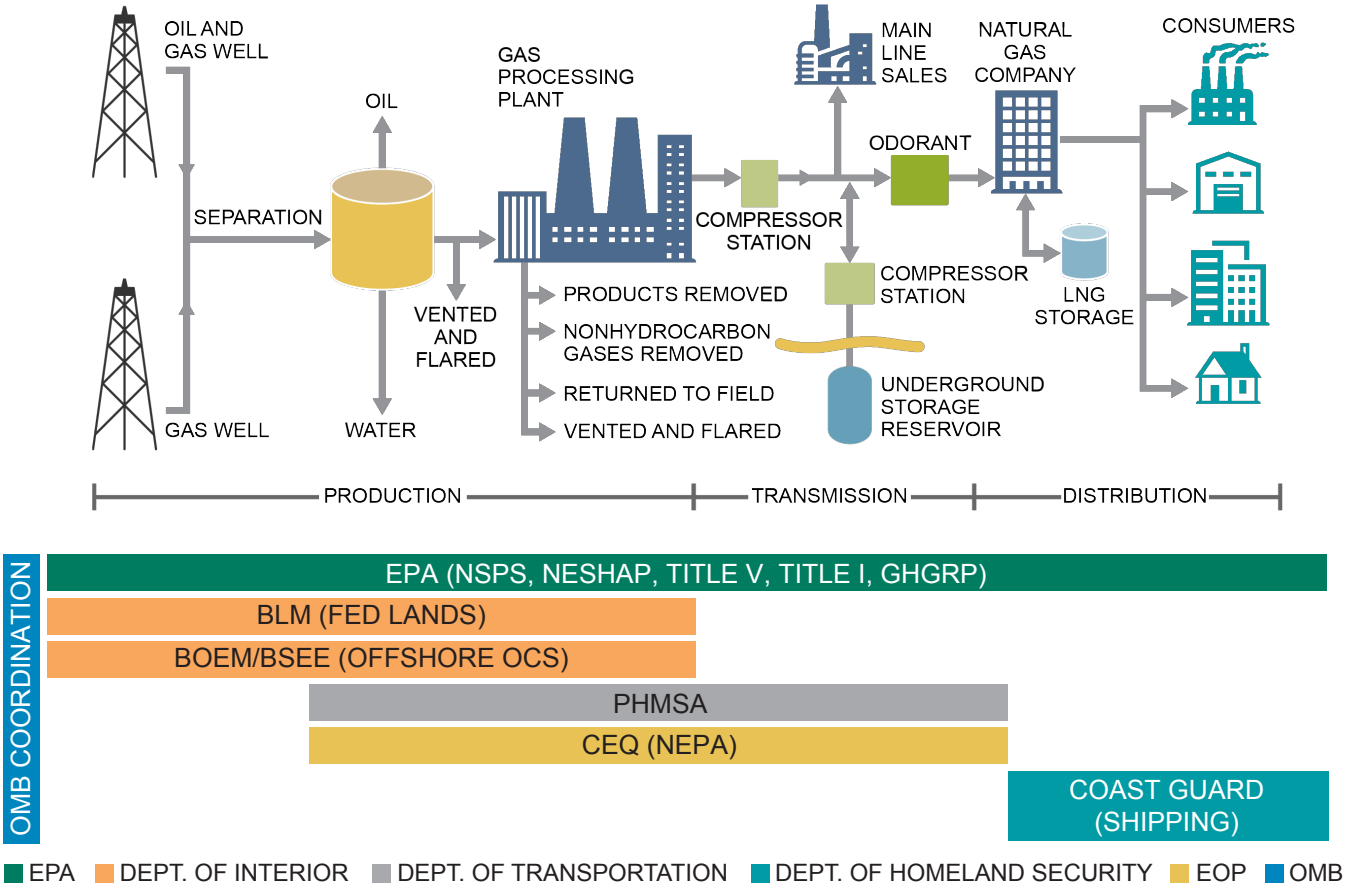
B. Federal Policy

In the United States, there is a complex regulatory environment with multiple agencies involved directly or indirectly in the activities that influence GHG reporting, reductions, or control requirements in the natural gas supply chain (Figure 1-27). Some supply chain segments, like natural gas production, may include regulations by more than one federal agency.

The following sections describe some of the roles and regulations for federal agencies with respect to GHG emissions from natural gas supply chains.

1. EPA

EPA is the principal federal agency with the authority to regulate GHG emissions across the *entire* oil and natural gas supply chain. The CAA



Note: This EIA figure combines distinct supply chain segments of production, gathering and boosting, and processing in one category for ease of display.

Source: EIA.

Figure 1-27. *Examples of Federal Regulations Across the Oil and Natural Gas Supply Chain*

authorizes EPA to develop and enforce regulations to control air pollution, including GHG emissions. Owners and operators must identify and comply with all applicable CAA rules, where applicability depends on several factors (e.g., industry sector, potential to emit, date of construction, modification or reconstruction, activity, location, and local air quality factors). The EPA air program regulations are divided into various sections where the same industry sector can be regulated under multiple sections. For example, a facility operating in the oil and natural gas production segment may have an array of emissions limitations, work-practice standards, monitoring, recordkeeping, and reporting obligations under many different sections of EPA rules. Additional federal agencies have overlapping responsibilities for permitting and regulating various activities across the oil and natural gas supply chain that may be additional to EPA requirements.

The EPA generally regulates "stationary sources" with three distinct approaches under the CAA. The first is via direct emissions control requirements segment by segment, which are often referred to by their individual programs such as NSPS or National Emissions Standards for Hazardous Air Pollutants/Maximum Achievable Control Technology (NESHAPs/MACT). These programs set out a suite of requirements for emissions sources within source categories on a national basis. The second is through permitting of certain individual facilities, generally that exceed certain thresholds of emissions. The third (which includes significant overlaps with the first two) is via programs to ensure national ambient air quality is maintained with a level of certain criteria pollutants below an established level, which is deemed protective of public health, welfare, and the environment.

a. Direct Emissions Control Requirements

EPA first regulated the "crude oil and natural gas production" source category in 1984 with NSPS KKK (equipment leaks and compressors at gas processing plants) and NSPS LLL (SO_2 emissions from sweetening units). EPA finalized emissions control requirements on the oil and natural gas production and natural gas transmission and storage source categories in 1999 with the promulgation of its NESHAPs[79] for major sources[80] in those segments. The targets of those regulations were hazardous air pollutants (HAP), namely benzene, toluene, ethylbenzene, toluene, and n-hexane. Incidental reductions in VOCs and methane were identified and credited as cobenefits that would result from the implementation of the source controls in that rulemaking. EPA subsequently finalized a NESHAP for area sources[81] in the oil and natural gas production source category in 2007. NESHAPs apply to both existing and new sources of emissions from a regulated source category.

In 2012, EPA finalized its first set of NSPS for Crude Oil and Natural Gas Production[82] and conducted its statutory review of the NESHAPs (Figure 1-28). The 2012 NSPS OOOO also included the technology review of KKK and LLL, in addition to expanding the regulations to include additional emissions sources in production, processing, gathering and boosting, and transmission and storage. While the NSPS targeted criteria pollutants (VOCs and SOx) and the NESHAP revisions targeted air toxics, incidental reductions in methane were identified and credited as cobenefits. NSPS regulations apply only to facilities constructed, reconstructed, or modified as of the date of the publication of the notice of proposed rulemaking in the *Federal Register*.

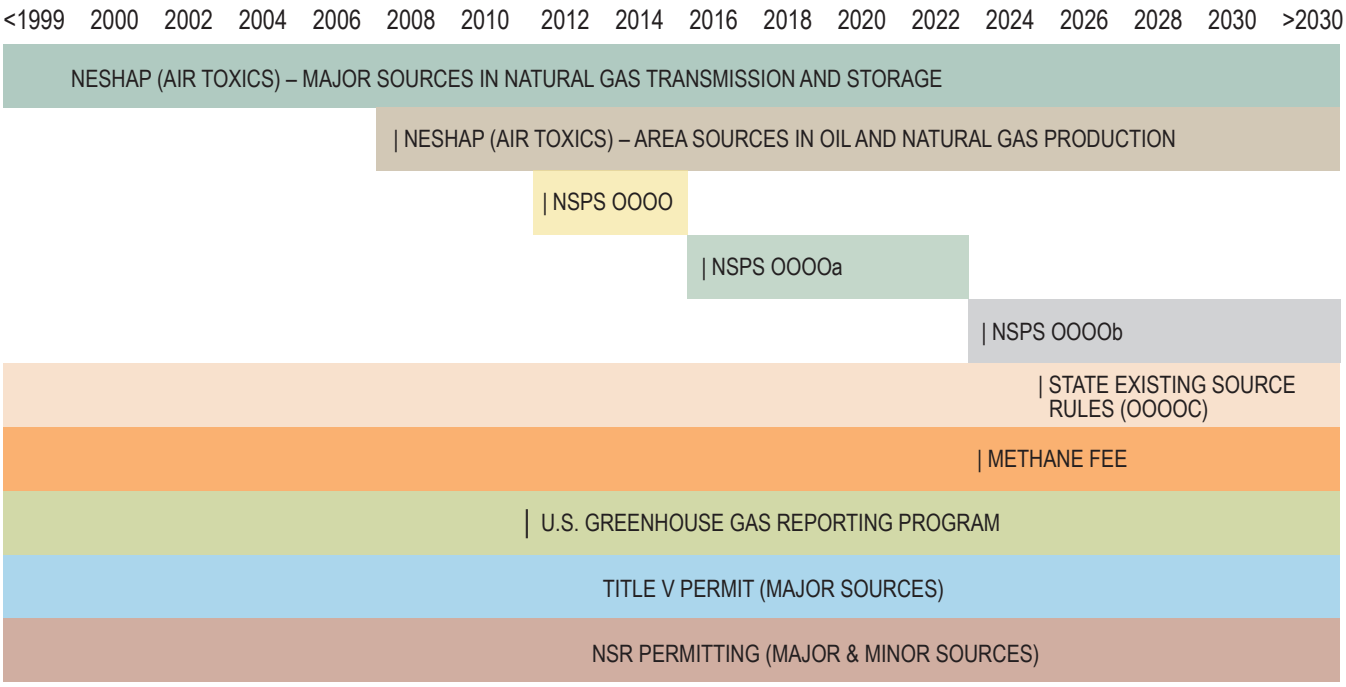
In 2016, EPA proposed additional NSPS regulations tightening the requirements and included

79 40 CFR 63 subparts HH and HHH cover Oil and Natural Gas Production and Natural Gas Transmission Storage Facilities, respectively. Subparts EEEE and ZZZZ include provisions specific to organic liquid (nongasoline) storage such as in storage terminals, crude oil pipeline stations, etc., and stationary reciprocating internal combustion engines, respectively. Limitations on HAP from these sources often limit methane emissions as a cobenefit. n.d. https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-63?toc=1.

80 "Major sources" are defined as a stationary source or group of stationary sources that emit or have the potential to emit 10 or more tons per year of hazardous air pollutant, or 25 tons per year or more of a combination of hazardous air pollutants.

81 The term "area source" means any stationary source of hazardous air pollutants that is not a major source.

82 The NSPS for the Crude Oil and Natural Gas Production source category regulate by source type within the category more broadly. For example, the 2012 NSPS-regulated VOC emissions from gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels and leaking components at onshore natural gas processing plants, as well as SO_2 emissions from natural gas processing plants.



Notes: Colored bars indicate vintage of facilities that may have applicability to a rule.
| Rule Title indicates the approximate timing of the rule coming into effect.

Figure 1-28. *Examples of EPA Federal Regulations Applicable to the Oil and Natural Gas Supply Chain and Their Timelines*

methane as a regulated pollutant with limitations in the rule. Although there was little impact on the actual pollution control measures that upstream operators would have to incorporate for their affected facilities compared to if the rule had not specifically identified methane as a regulated pollutant, the implications of this action were significant. This action triggered an obligation for EPA to promulgate emissions guidelines defining minimum standards that states must consider in their plans for all existing sources. Facilities constructed prior to the applicability date of NSPS OOOO in 2012 that were not modified in a manner that triggered applicability for any of the OOOO series would be subject to these emissions guidelines for existing sources.

In 2020, EPA revised the 2016 NSPS by removing sources in the transmission and storage segment from the rule, eliminating methane as a regulated pollutant, and amending certain requirements specific to VOC emissions from the production, processing, and gathering segments.

The 2020 revisions were reviewed by Congress under the Congressional Review Act. The June 2021 Congressional Review Act Resolution of Disapproval was passed, reinstating the methane emissions standards of the 2016 rule and the transmission and storage segment as part of the regulated source category. Later that year, EPA proposed revisions to the NSPS (NSPS OOOOb) and proposed the first nationwide emissions guidelines (EG OOOOc) to regulate methane from existing sources. EPA issued a supplemental proposal in 2022 that expanded on the 2021 proposal and included revisions to certain standards because of comments received on the 2021 proposal.

EPA announced that it had finalized these rules in December 2023, which cover the production, gathering and boosting, and gas processing segments. The rules first apply to new sources that commenced construction, modification, or reconstruction after December 6, 2022, and do not immediately impose binding requirements on existing sources. However, the finalized EG

OOOOc provisions direct states and Tribes to develop and submit SIPs to establish performance standards for all existing facilities within the subsequent 24 months of rule finalization. The collection of rules imposes control requirements for all facilities across the United States with nearly identical requirements for the new and existing facilities. This means retrofitting equipment and establishing new work practices at hundreds of thousands of facilities that, in some cases, are decades old.

Provisions included in the final rule for OOOOb and OOOOc include:[83]

- **Expanded LDAR provisions:** LDAR requirements depend on facility type but include all facilities. The simplest sites in terms of equipment count require quarterly personnel visits where other facilities require periodic personnel visits and additional monitoring with OGI handheld camera on a semiannual, quarterly, or bimonthly basis, depending on facility type. EPA allowed for the use of advanced methane monitoring technology meeting certain minimum criteria and attaining approval for use by the administrator in lieu of OGI camera inspections.
- **Routine flaring of associated gas limitations:** Routine flaring of associated gas will phase out and be eventually prohibited from newly constructed wells. Subsequent existing source rules must similarly require sale or beneficial use of associated gas with certain exceptions for low-volume wells or technical infeasibility.
- **Creation of a super-emitter program:** Where EPA certifies a third-party entity for surveillance of emissions events, owners and operators are required to take action to investigate any identified large emissions events, those with observed emissions rates exceeding 100 kg/hr of methane, upon notification. EPA additionally amended prior rules (NSPS OOOO and NSPS OOOOa) so that this provision applies broadly to all regulated facilities, not only to new facilities.
- **Process controller and pump vent emissions eliminated:** The largest source category of methane emissions from upstream facilities, according to the national emissions inventory, will be eliminated, with narrow exceptions in Alaska without access to electric power. Process controllers and pumps, often referred to as natural gas-driven pneumatic controllers and pumps, must be changed out for nonemitting options, including compressed air-driven pneumatics or electric options.
- **Retrofits of storage vessels (tanks) for emissions control:** Existing tank batteries with a minimum threshold of methane emissions potential will require retrofit to capture tank vapors.

b. New Rule Impacts

EPA projects aggregate methane emissions reductions of 1,500 million metric tons of CO_2e from the combination of the finalized new and existing source requirements over the 2024 to 2038 time period.[84] The majority of the emissions (~60%) are projected to come from the existing source requirements, but the nearly 40% of emissions reductions that are attributable to the new source requirements will begin accruing immediately. EPA similarly projects 14.5 and 0.5 million metric tons of coemitted VOCs (ozone precursor) and hazardous air pollutant emissions reductions, respectively. Figure 1-29 illustrates EPA assumptions on the number of national well sites that will be included under new LDAR requirements due to NSPS OOOOb and EG OOOOc. The increase in the late 2020s is attributed to existing source requirements entering at the state level, and the EPA is projecting a decrease in national well count in the 2030s.

While the promulgation of final rules is an important step to defining requirements and timelines, it should be noted that the emissions reductions come from the installation of control technologies and the implementation of LDAR programs by operators. These programs take both

83 EPA. "40 CFR Part 60 - Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." Final rule. *Federal Register*. Vol. 89, no. 47, March 8, 2024: 16820. https://www.govinfo.gov/content/pkg/FR-2024-03-08/pdf/2024-00366.pdf.

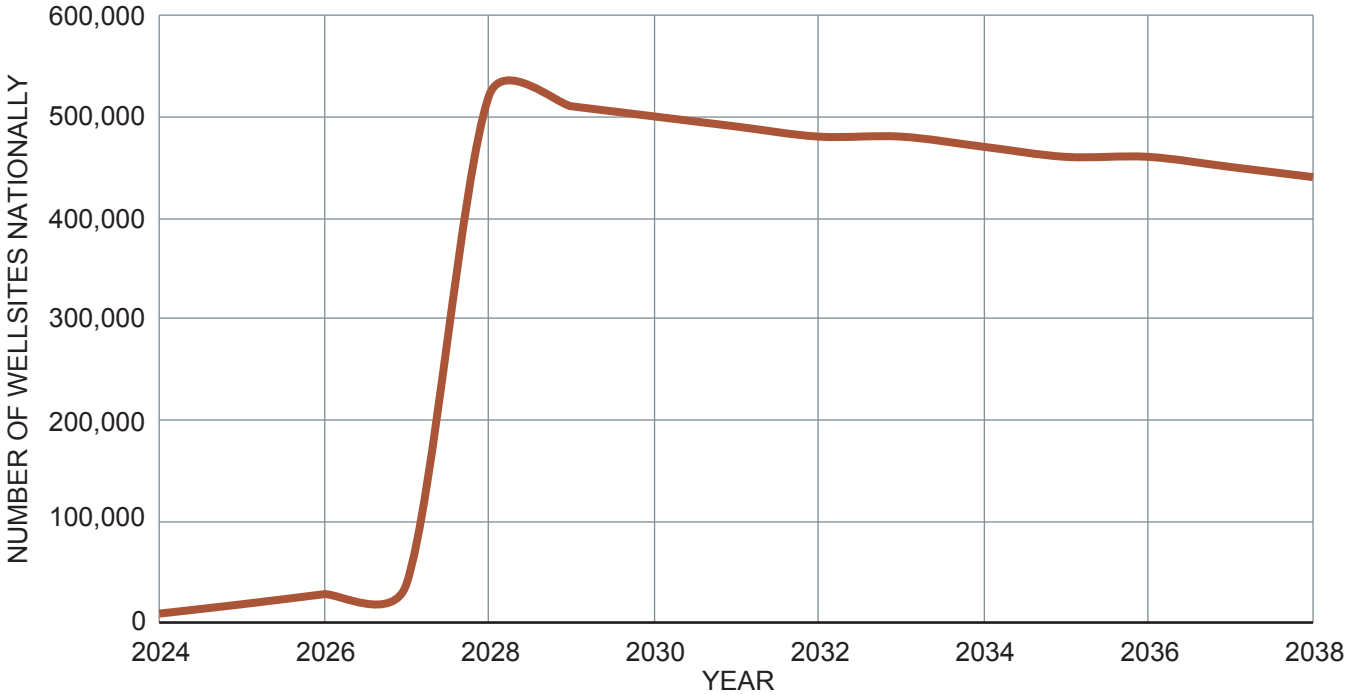
84 EPA. "Regulatory Impact Analysis of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." December 2023. https://www.epa.gov/system/files/documents/2023-12/eo12866_oil-and-gas-nsps-eg-climate-review-2060-av16-ria-2023l130.pdf.

personnel time and expenditures to implement. EPA estimates that capital costs associated with compliance with NSPS OOOOb and EG OOOOc are expected to significantly spike around 2028, at the onset of retrofit requirements for existing sources, by nearly a factor of 10 above the annual range of $1.4–2.1 billion. Total discounted compliance cost over the 14-year time period, accounting for the revenue from product recovery, is projected by EPA at $14 billion. Nearly 64% of that is attributable to future existing source retrofits. Thus, implementing this federal regulatory program is expected to require significant investments by operators.

c. *Facility Permitting*

Title V permits are often referred to as operating permits. These permits consolidate all applicable emissions limitations into a single, authorizing instrument with all applicable CAA requirements for the source (facility) subject to the permit. These permits are required to operate *major sources* of emissions, which means that a facility has actual emissions or the potential to emit at or above the major source threshold for any "air pollutant." The default is 100 tons/year, barring separate legislation or rulemaking by pollutant. An example of a lower threshold is the threshold of 10 tons/year for any listed hazardous air pollutant (e.g., benzene, toluene, n-hexane) or 25 tons/year for any combination of HAPs. Thresholds are lowered for pollutants in areas where the local air quality is degraded relative to the NAAQS with respect to that pollutant (e.g., reduced VOC and NO_x thresholds in ozone nonattainment areas). EPA has generally not required nonmajor sources to get permits, with some exceptions. A source cannot trigger Title V permitting obligations solely due to its GHG emissions, meaning that it must exceed the major source threshold for one or more other pollutants at which point GHG emissions limitations will be included in the permit.

Major New Source Review (NSR) permits are often referred to as preconstruction permits and require all industrial facilities to install modern pollution control equipment when they are



Source: EPA, 2023, "Regulatory Impact Analysis of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," Table 2-6.

Figure 1-29. *EPA Estimates of Incrementally Regulated Production Well-Site Facilities Requiring LDAR Under NSPS OOOOb and EG OOOOc from 2024-2038*

built or when changes that significantly increase emissions are made. These permits must be obtained prior to commencement of construction. The NSR program applies to pollutants relevant to criteria pollutants, including ozone, nitrogen oxides, sulfur oxides, particulate matter, lead, and carbon monoxide, and a few other species, such as sulfuric acid mist and hydrogen sulfide. NSR permitting applies to both major and minor sources, though permitting requirements may be significantly streamlined for minor sources. In a decision in 2014, the Supreme Court stated that EPA could not treat GHG emissions as an air pollutant for purposes of determining whether a source is a major source but could continue to require limitations on GHG emissions based on implementation of Best Available Control Technology for sources that required Prevention of Significant Deterioration Permits based on criteria pollutant emissions levels.

Like direct emissions standards, limiting pollutants such as VOCs or other hydrocarbons also limits methane emissions, since VOCs and methane are coemitted from many of the same sources across the oil and natural gas supply chain, and emissions controls are generally effective for both pollutants. NSRs, which are generally preconstruction permits, occur before new facilities or major modifications commence, while Title V permits have wider application to major sources that exceed the emissions threshold, including for active facilities.

d. Emissions Reporting

The GHGRP requires reporting of GHG data and other relevant information from large industrial GHG emissions sources, fuel and industrial gas suppliers, and carbon dioxide injection sites in the United States. An entity is required to report if their emissions exceed a threshold of 25,000 metric tons CO_2e/yr in a covered sector in the program. Methane is included with a GWP of 25, although EPA proposed in 2023 to adopt AR5 GWP100 for methane, which adjusts the GWP to 28.

Reported data from the prior calendar year are made publicly available in October of each year and are used to inform the GHGI, which is an annual EPA-prepared accounting of GHG emissions on a national basis. The GHGI is the official inventory that is submitted to the UNFCCC to track progress against U.S. climate commitments.

The GHGRP departs from EPA's long-standing analogous reporting program for air toxics, the Toxic Release Inventory, in that GHGRP is highly prescriptive on which sources are included in reporting and exactly how the emissions estimates are derived (Figure 1-30). Instructions on which sources to include and how to estimate emissions (highly dependent on national, annual, and average emissions factors) are codified across several subparts with the Part 98 GHGRP regulations. Segment definitions are also highly prescriptive. Changes to GHGRP methods require a rulemaking process and public comment period, as described in an earlier section of this chapter.

e. Inflation Reduction Act

The Inflation Reduction Act of 2022 (IRA) covered a range of topics, including healthcare, taxes, clean energy, and environmental programs. Provisions impacting the oil and natural gas supply chain are summarized in this section.

Funding authorizations include funding of up to $1.55 billion to EPA to issue grants, rebates, contracts, loans, and fund other activities. The IRA specifies, among other things, that this funding should be allocated for financial and technical assistance to owners and operators of applicable facilities to prepare and submit reports for the GHGRP, for methane emissions monitoring ($20 million), mitigation of legacy air pollution from petroleum and natural gas systems ($850 million for reductions at natural gas facilities and $700 million for similar activities at marginal conventional wells), and improving climate resiliency of communities and petroleum and natural gas systems.

EPA is instructed to amend the GHGRP, including methods within the GHGRP Subpart W to include empirical data and to establish a waste emissions charge under the Methane Emissions Reduction Program. This program would impose a waste emissions charge on operators for methane emissions that exceed a particular threshold identified for each segment across the supply chain and uses Subpart W reporting as the

PRODUCTION & PROCESSING

1. Onshore Petroleum & Natural Gas ★ Production
2. Offshore Petroleum & Natural Gas Production
3. Petroleum Refining
4. Gathering and Boosting ★
5. Gas Processing Plant ★
6. Natural Gas Liquids (NGL) Supply

NATURAL GAS TRANSMISSION & STORAGE

7. Transmission Compressor Stations ★
8. Underground Storage ★
9. Liquified Natural Gas (LNG) Storage
10. LNG Import-Export Equipment
11. Natural Gas Transmission Pipeline

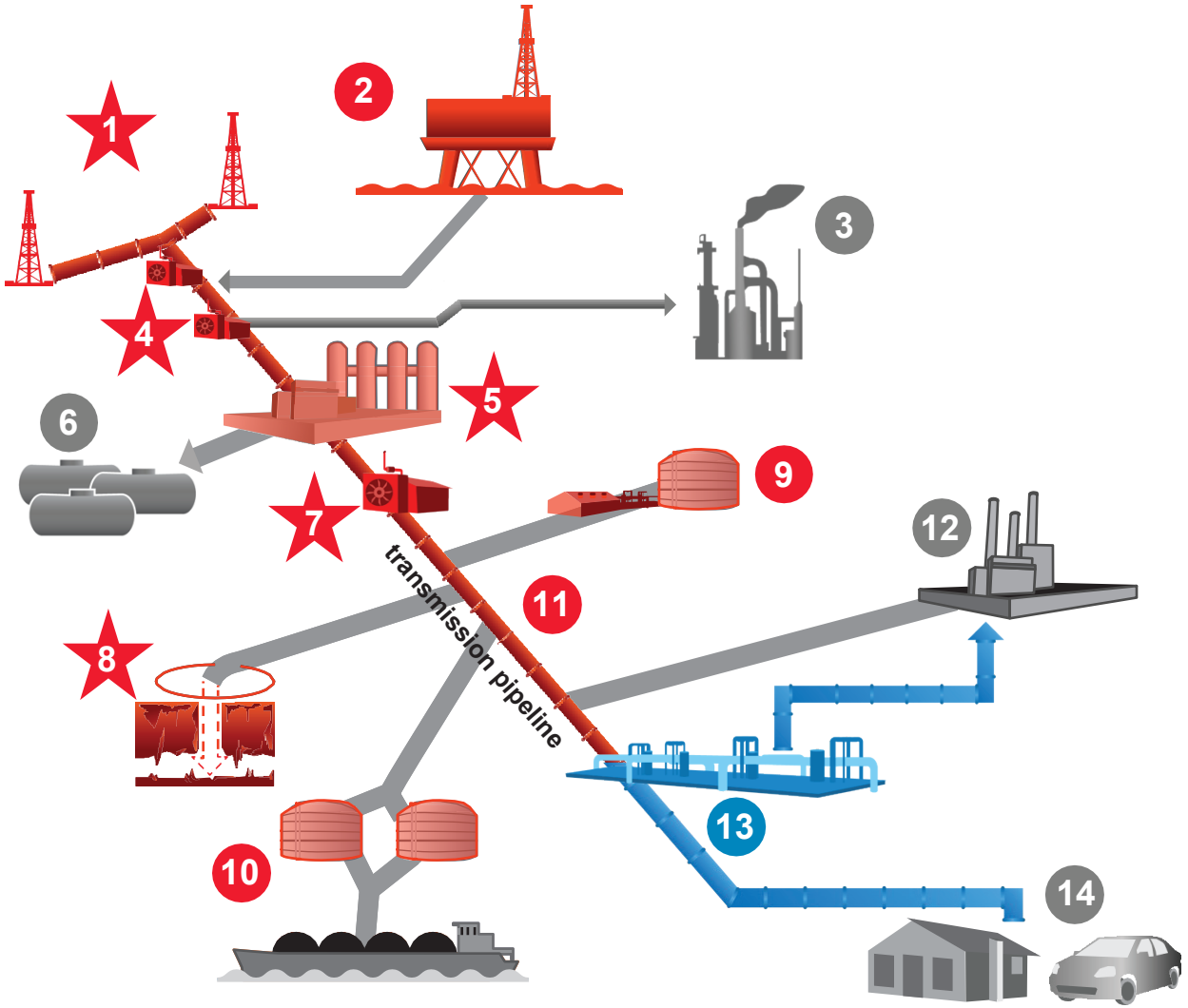
DISTRIBUTION

12. Large End Users
13. Natural Gas Distribution
14. Natural Gas & Petroleum Supply to Small End Users

- GHGRP Subpart W industry segments subject to Waste Emissions Charge
- GHGRP Subpart W industry segments not subject to Waste Emissions Charge
- ★ Industry segments that may have facilities subject to final NSPS OOOOb and EG OOOOc

NOTES:

- Segments without boxes are not reported under Subpart W
- Covered sources vary by industry segment
- There are sources covered by NSPS/EG but not WEC where facility emissions are below threshold of 25,000 metric tons CO_2e



Source: EPA, 2024, "GHGRP and the Oil and Gas Industry."

Figure 1-30. *Oil and Gas Industry Overview by EPA GHG Reporting Subpart*

information collection mechanism. Distribution is not included within the program.

The waste emissions charge is expected to start with data from 2024 reporting at $900 per metric ton of methane. The fee is expected to increase to $1,200 per metric ton in 2025 and $1500 per metric ton in 2026. The methane fee sets waste emissions thresholds by segment, generally as some percent of natural gas sent to sale from the facility, ranging from 0.05% to 0.20%, depending on the segment. The IRA methane fee also allows for the "netting" of emissions. This allows companies flexibility to offset emissions levels over the intensity threshold in some operations, with others that are sufficiently below for the same operator.

In addition to aggregate performance below the threshold level, there are three exceptions to the methane charge stated in the IRA. First, if the emissions are caused by "unreasonable delay" in environmental permitting of necessary gathering or transmission infrastructure for offtake of increased volume because of methane emissions mitigation implementation. Second, facilities subject to and in compliance with subsequent CAA methane regulations are exempted. Specifically, this exemption would be available if the facility is in compliance with methane emissions standards established by EPA under Section 111(b) or (d) of the CAA, if these standards are in effect in all states with applicable facilities, and if such standards achieve equivalent or greater emissions reductions compared to those set forth in the methane emissions standards proposed by EPA in 2021.[85] For this exemption to be available, the final rules would need to be in place by January 1, 2024, when methane emissions are expected to become subject to the waste emissions charge. There is likely to be a timing mismatch between the start of the waste emissions charge and implementation timelines, particularly for existing sources, under EG OOOOc. Third, any well that has been permanently shut in and plugged in the prior year or earlier in accordance with applicable closure requirements are exempt from the waste emissions charge.

While the IRA outlines these exemptions from the waste emissions charge, the implementing rules that are being developed by EPA may make these exemptions accessible to different degrees, based on agency interpretation and decisions on applicability requirements. There are key questions that remain in terms of implementation for both the Methane Emissions Reduction Program and its relationship with NSPS OOOOb and EG OOOOc.

The carbon dioxide capture credit (45Q) was extended, such that the deadline for start of construction moved to January 1, 2033. In addition, the threshold amount of carbon dioxide that must be captured to qualify was reduced, and the tax credit increased for both industrial carbon capture and direct air capture. For industrial carbon capture, the credit value increased from $50 per metric ton of carbon dioxide to up to $85 for geologic storage and up to $60 for utilization. Credits for direct air capture were established at $180 per metric ton for geologic storage and $130 per metric ton for utilization. For direct emissions from the natural gas supply chain, the 45Q credits are a potential new financial incentive that could help to reduce emissions from point sources, such as reservoir carbon dioxide separated in the gas processing segment and potentially combustion-related capture projects at larger facilities across the supply chain.

The clean hydrogen tax credit (45V) applies to hydrogen that has been produced through a process that results in a well-to-gate life cycle GHG emissions rate below 4 kg of CO_2e per kg of hydrogen. According to the International Energy Agency (IEA),[86] the global average CI of hydrogen production in 2021 was nearly 10 kg CO_2e/kg hydrogen, about two-and-a-half times the definition of clean hydrogen under the new tax credit, where the hydrogen is largely derived from natural gas without carbon capture. The provision of the IRA has relevance to the natural gas supply chain. Low carbon intensity hydrogen derived from natural gas feedstocks, often called blue hydrogen, could be eligible for the tax credit if well-to-gate life cycle emissions are sufficiently reduced. This would require the use of carbon capture to reduce

85 "EPA Proposes Methane Emission Regulation." November 2021. https://www.jonesday.com/en/insights/2021/11/epa-proposes-methane-emission-regulation-for-existing-oil-and-gas-production.

86 IEA. "Hydrogen." n.d. https://www.iea.org/reports/hydrogen-supply.

emissions during the hydrogen production phase and a sufficiently low CI supply of natural gas as feedstock to the process. Improvements in natural gas monitoring, reporting, and verification (MRV) frameworks and reduced supply chain emissions intensity would support market development, if such reductions can be used in estimating supply chain intensities in 45V.

DOI oil and gas leasing changes included increases in the minimum royalty rate for new offshore[87] oil and gas leases from 12.5% to 16.6% and set a maximum royalty rate of 18.8% for new offshore oil and gas leases for 10 years. The IRA also included specific directions on offshore leasing activities, including requiring a minimum offering of parcels for fossil fuels leases in order to issue new solar or wind rights-of-way on federal lands, elimination of noncompetitive leasing, and establishment of a higher minimum bids on federal leases. Additionally, the scope of royalty collection for natural gas produced on federal land and the outer continental shelf (OCS) was expanded to include "gas that is consumed or lost by venting, flaring, or negligent releases through any equipment during upstream operations," with certain exceptions.

According to the Congressional Research Service,[88] the combination of funding and financial incentives of the IRA are likely to facilitate U.S. national GHG reductions from many sectors beyond pre-IRA projections.

"This deployment would likely reduce or avoid some quantity of GHG emissions compared to baseline projections. Several recent analyses by researchers generally estimate that under baseline conditions (i.e., without IRA), U.S. GHG emissions would decrease by 24% to 35% by 2030 compared to 2005 levels. The same analyses estimated that IRA could reduce U.S. GHG emissions by 32% to 40% by 2030 compared to 2005 levels. The range of estimates from the baseline and IRA scenarios is due to varied assumptions in the models, such as future oil and natural gas prices, among other uncertain factors. Actual GHG emissions levels will depend on how the provisions are implemented, the growth rate of the U.S. economy, fuel prices, and a range of other factors."

f. Proposed Update to Subpart W

On August 1, 2023, EPA issued a proposed rule[89] with updated methodologies for Subpart W, primarily concerning methane emissions, in response to section 60113 of the IRA directing EPA to "revise the requirements of Subpart W [...] to ensure the reporting under such subpart, and calculation of charges [...] are based on empirical data [and] accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the administrator, to demonstrate the extent to which a charge under subsection (c) is owed."[90] A final rule is expected in 2024 with changes starting for reporting year 2025 under the program. As an important caveat, EPA specifically excluded considerations around impacts on the waste emission charge and or additional costs to operators for new requirements under this proposed rule, indicating that these would occur separate rulemaking process.

The first type of proposed change is updating methodologies for sources categories already covered under the program. For many, but not all sources, EPA has proposed changes that would update default emissions factors under the program but allow for substitution of source-specific measurement data or performance data. For example, the proposed rule included a provision to lower default flare destruction efficiencies from the current 98% to 92% with options for operators to justify 95% based on flare upgrades included in

87 Oakes, Hannah. 2022. "The IRA Offshore Energy Leasing Provisions' Potential Impacts-Environmental & Energy Law Program." Harvard Law School. August 25, 2022. https://eelp.law.harvard.edu/2022/08/the-ira-offshore-energy-leasing-provisions-potential-impacts/.

88 Congressional Research Service. "Inflation Reduction Act of 2022 (IRA): Provisions Related to Climate Change." Updated October 26, 2023. https://crsreports.congress.gov/product/pdf/R/R47262.

89 EPA. "40 CFR Part 98 Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems." *Federal Register*. Vol. 88, No. 146, August 1, 2023: 50282. https://www.govinfo.gov/content/pkg/FR-2023-08-01/pdf/2023-14338.pdf.

90 EPA. "40 CFR 98 Methane Emissions and Waste Reduction Incentive Program and Revisions to the Mandatory Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems." Fall 2022. https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202210&RIN=2060-AV83.

the proposed rule for NSPS OOOOb or 98% if flares comply with standards for refineries and chemical plants. For equipment leaks, the proposed rule includes higher default equipment-level factors based on more recent field campaigns but allows for the use of leak or no-leak factors for sites with LDAR programs, including the option to substitute company-specific leaker factors for operators with more than 50 component measurements in one year. EPA also proposed updated engine slip factors that would significantly (~22x) increase methane emissions estimates for lean-burn engines, which have been commonly installed throughout the natural gas supply chain due to lower NO_x emissions profiles than rich-burn engines for reciprocating compressors. There has been some criticism that EPA did not properly interpret data in the underlying studies that it used to reference for new emissions factors and that it would be, in some cases, forcing the development of costly measurement programs for sources, like intermittent vent pneumatics, that it is trying to phase out in the short term under NSPS OOOOb and EG OOOOc.

While there have been scientific field campaigns to measure methane emissions from source categories like pneumatic controllers, equipment leaks, and liquid unloading activities, with sample sizes of hundreds of emissions sources, operator-specific measurements by source category have been relatively uncommon in the sector. Obtaining such data is expected to be costly and labor intensive, require training on the use of new metering and measurement equipment, and the development of statistical tools to develop company-specific emissions factors from the collected data. The assurance processes for measurements and EPA acceptance of the measurement data for GHGRP reporting are still being considered. Such source-specific direct measurements need a different class of detection and measurement equipment, compared to equipment-level, site-level, or basin-level approaches that are discussed in Chapter 3.

The second type of proposed change would expand the granularity of reported GHG data. Currently, for Subpart W reporting, many emissions sources in the production and gathering and boosting segments are reported at the basin level (i.e., all Permian production operations) or sub-basin (i.e., county-level) for an operator. Proposed changes would include additional disaggregation of emissions reporting down to the site level in addition to basin-level reporting on which the waste emission charge calculations would be based. While EPA argues that the changes are needed for improvements to data quality, there are concerns that data disaggregation may not help meet this goal, particularly for emissions-factor-driven calculations that are intended to be used over larger sample sizes, and that more line-item entries may increase the likelihood of unintended errors in EPA submissions.

The third type of proposed change is the inclusion of a new category for "other large release events" that is a catch-all category for detected emissions that exceed 100 kg/hr methane or for overall events that exceed 250 metric tons CO_2e (~9 metric tons of methane with a GWP of 28). This category has been proposed to include both large, infrequent events (like a well blowout) and detections from third-party monitoring of operations, although EPA did not fully define the data flow mechanisms and tie-in with the super-emitter program set out in NSPS OOOOb. For third-party detections, EPA has proposed a default duration of 182 days (~6 months) unless an operator has inspection or parametric data to constrain the duration to a shorter period. This has drawn some criticism from operators since the literature suggests that such events are typically less than a few days in duration. Smaller operators that fall below the current 25,000 metric ton CO_2e annual reporting threshold have expressed concern that one such detection, particularly for a site with little instrumentation to constrain duration, could place them over the reporting threshold for both the event and all other sources, with cost implications both for the waste emissions charge and to implement GHG reporting that would not have otherwise been required.

The fourth type of change that EPA included in the proposed rule is the inclusion of new source categories for methane reporting, for which methodologies and reporting mechanics had been previously unavailable but that could be material GHG emissions sources in specific sectors. For example, in the LNG sector, reporting methodologies in the GHGRP had been previously based

on LNG peak shaving (i.e., small-scale facilities) versus the large-scale liquefaction facilities for LNG export that have been constructed on the Gulf Coast. Large-scale LNG facilities typically include additional gas treatment and processing prior to the liquefaction stage, and the proposed updates to the GHGRP include methane emissions reporting methodologies for nitrogen rejection units and acid gas recovery units for the first time. For multiple supply chain segments with compression, emissions associated with centrifugal dry seals, which are designed to have lower-methane emissions than unabated centrifugal wet seals, are also proposed to be reported for the first time.

There has also been criticism from some stakeholders that the proposed rule does not meet the directive of the IRA to amend Subpart W to require empirical data that accurately reflects the total methane emissions and waste emissions from the applicable facilities, nor does it allow owners and operators of applicable facilities to submit empirical emissions data from advanced technologies deployment. The proposal allows the optional use of measured emissions data associated with "other large release events" but this is not allowed for other uses like screening flares or tanks for emissions where they could offer a pathway to more cost-effective compliance than the source-level direct measurement approaches proposed by EPA.

EPA did not provide aggregate changes in expected emissions because of the Subpart W proposed rule, so it is difficult to assess the overall impacts on methane emissions reporting in the GHGRP. Generally, the expectation is that emissions will be higher than current Subpart W reporting, particularly for flares and lean-burn engines.

FINDING 21: **The oil and natural gas supply chain is heavily regulated, including rules limiting GHG emissions. The oil and natural gas supply chain is subject to a complex and overlapping suite of regulations, which vary depending on state, county, and local factors as well as applicability to regulations of varying federal agencies.**

FINDING 22: **Beyond existing voluntary and state-level efforts to reduce emissions, two in-flight federal programs hold the potential for significant reductions of emissions from the sector in coming years: Inflation Reduction Act of 2022 (Methane Emissions Reduction Program) and EPA methane rules (OOOOb and OOOOc).**

2. Environmental Protection on Federal and Tribal Lands

There are 325 federally recognized American Indian reservations in 14 states, mainly in the western half of the United States. Generally, regulation of GHGs, or any air pollutant, on Tribal lands is carried out by EPA. Each EPA region is responsible for enforcing federal regulations, Title V (Part 71) permits, and other permits on Tribal lands. Tribes can be granted treatment as a state authority to either implement federal regulations or Tribal-specific regulations, similar to states, as long as these minimally meet federal requirements. Typically, federal regulations apply on reservations, with EPA as the enforcement authority, but there are some exceptions and reservation-specific circumstances.

EPA has permitting authority and jurisdiction on all federal lands (BLM, national forest, etc.). For lands within the exterior boundaries of Indian reservations that are designated Tribal lands (trust land), EPA typically has jurisdiction. For lands within reservation boundaries that are privately owned (fee lands), jurisdiction depends on the specific laws and agreements in place for the individual Tribes. Most often, regulation of fee lands owned by non-Tribal individuals or entities are regulated by either the state or EPA. There are instances where Tribes have been granted authority to act as an agent for EPA and enforce federal regulations (e.g., the Navajo Nation in the Four Corners region of the Southwest has authority to issue and enforce Part 71, Title V operating permits). The Southern Ute Indian Tribe, in southwest Colorado, is the only Tribe in the nation to have developed its own Title V operating permit program (Part 70), and they have also been delegated enforcement authority for NSPS, MACT, and NESHAPs subparts of the federal regulations,

as they apply to the Title V permits. However, regulatory authority of GHGs has not yet been specifically delegated to any Tribes unless those regulations are included in a Title V operating permit. The Navajo Nation and Southern Ute Indian Tribe are currently in the process of seeking delegations of authority to administer minor source permitting programs on their respective reservations. This will potentially give these Tribes permitting and enforcement authority for NSPS OOOOb and EG OOOOc.

3. Pipeline and Hazardous Materials Safety Administration (PHMSA)

PHMSA, an agency within the DOT, is principally responsible for safe transportation of hazardous materials and the safe operation of pipelines in the United States. This results in a layer of design and construction standards (e.g., criteria for pipeline materials, welding procedures, corrosion prevention, burial depth, pressure testing), operational and maintenance standards (e.g., monitoring and inspection), damage prevention measures (such as the familiar procedures for marking and locating pipeline prior to excavation), public engagement requirements, and reporting and recordkeeping. PHMSA, like EPA, only sets federal standards, whereas states may set their own or different requirements. For pipelines subject to federal oversight, state requirements must meet federal standards at a minimum. As a result, navigation of the diverse regulatory landscape can be particularly challenging for interstate pipeline operators.

In May 2023, PHMSA announced a proposed rule[91] seeking to reduce methane emissions from pipelines, underground storage facilities, and LNG plants. The proposal included increased leak detection and patrolling requirements, explicit timelines for repair of all leaks, practices that minimize venting during maintenance activities and blowdowns, and reporting requirements for events exceeding 1 million cubic feet of gas released. While the coverage is larger for the transmission and distribution segments, PHMSA regulations are estimated to cover ~23% of gathering gas line mileage in the United States.

PHMSA also collects information on lost and unaccounted for (LAUF) gas related to distribution systems. LAUF is an estimate that accounts for both measurement inaccuracy from different meters in the system and unknown leaks in the system, but LAUF cannot resolve the relative fraction of each. Due to uncertainties with data collection, PHMSA and EIA estimates for LAUF should not be used to estimate methane emissions from distribution systems.[92]

4. Department of the Interior

Facilities on federal lands are subject to requirements from the BLM, a bureau within the DOI,

AIR QUALITY REGULATION BY THE SOUTHERN UTE INDIAN TRIBE

To simplify jurisdiction of air quality on the reservation and enhance Tribal sovereignty, the Southern Ute Indian Tribe entered into an intergovernmental agreement (IGA) with the state of Colorado in 1999 concerning air quality control on the Southern Ute Indian Reservation. This agreement established a joint Southern Ute Indian Tribe and state of Colorado environmental commission, whose purpose is to promulgate rules and regulations pertaining to air quality within the exterior boundaries of the Southern Ute Reservation. This IGA clarifies regulation on the reservation in that the regulations established by the commission apply to all lands within the exterior boundaries of the reservation, regardless of land status or facility ownership. Areas of regulation where the commission has not established rules are regulated by EPA, with the state of Colorado having the option to enforce programs enacted by the state that do not have a federal counterpart.

91 U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration. "49 CFR Parts 191, 192, and 193 Pipeline Safety: Gas Pipeline Leak Detection and Repair." *Federal Register*, Vol. 88, No. 96, May 18, 2023: 31890. https://www.federalregister.gov/documents/2023/05/18/2023-09918/pipeline-safety-gas-pipeline-leak-detection-and-repair.

92 U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration. "Lost and unaccounted for natural gas metrics." 2017. https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/news/17986/report-congress-lost-and-unaccounted-natural-gas-metrics-may-2017.pdf.

whose primary remit is the management and conservation of public lands owned by the federal government. The BLM is charged with balancing resource management, such as oil and gas extraction, with environmental protection, resource conservation, and habitat preservation. In addition to rules, the BLM is the issuer of leases for oil and gas development on federal lands. Analogously, facilities in the OCS[93] receive their leases and initial environmental requirements from the Bureau of Ocean Energy Management (BOEM), another agency within the DOI. The Bureau of Safety and Environmental Enforcement (BSEE), a distinct agency within the DOI, primarily focuses on safety and environmental protection during the operational phase of facilities operating in the OCS.

a. BLM

DOI has long regulated venting and flaring of publicly owned natural gas produced from federal leases and had royalty requirements.[94] In 2016, BLM adopted the waste prevention rule that would have required operators to capture natural gas that they would otherwise vent or flare with tightening capture targets over time. The rule included both specific source control and LDAR requirements. In 2018, this rule was vacated.

In November 2022, BLM issued an updated proposed waste prevention rule.[95] This rule, as proposed, sought to limit waste in several ways, including:

- **Redefining "Unavoidable Loss":** The proposal specifies when lost oil or gas would be classified as "unavoidably lost" (i.e., when it is royalty free) and when it would be classified as "avoidably lost" (i.e., when it is royalty bearing).
- **Prohibition on Venting:** Gas that cannot be captured must be flared (rather than vented), except under certain specified circumstances. Operators would be allowed to vent gas when flaring is technically infeasible, under emergency conditions, and when gas is vented through the normal operation of pneumatic equipment, among other circumstances.
- **Flare Performance:** Flares or combustion devices must be equipped with automatic ignition systems. BLM would be authorized to issue an immediate assessment of $1,000 upon discovering a flare that is not lit.
- **Waste Minimization Plans:** Requires operators submitting applications for permits to drill oil wells to develop waste minimization plans demonstrating the capacity of available pipeline infrastructure to take the anticipated associated gas production. Where the available information indicates that the plan does not take reasonable steps to avoid wasting gas, BLM may delay action on the permit until the operator adequately addresses the plan's deficiencies.

The Inflation Reduction Act of 2022 also directs BLM to impose royalties on gas produced, including natural gas consumed or lost by venting, flaring, or negligent releases through any equipment during upstream operations versus the current rule construct of imposing royalties on only gas produced and sold. The IRA law also puts a 48-hour limit on the exception for gas vented or flared and restricts it to emergency situations.

b. BSEE/BOEM

From a federal perspective, air quality regulation is split between the jurisdictions of BOEM and EPA. BOEM regulates air quality in the Central and Western Gulf of Mexico and the offshore portion of the North Slope Borough of Alaska. EPA is responsible for the balance of the OCS, which includes assets in the Gulf of Mexico east of 87.5°W longitude. States typically have air quality jurisdiction for three nautical miles beyond their coastline. From an emissions perspective, BOEM and BSEE are limited to regulating offshore emissions of criteria pollutants and their precursor emissions (VOC and NO_x) to the extent that they significantly impact the air quality of a state. Thus, BOEM regulations focus on programs

93 The OCS is generally beyond the coastal states' boundaries, extending to the outer edge of the continental margin. In the United States, this includes vast areas of the Gulf of Mexico, the Atlantic Ocean, the Pacific Ocean, and the Arctic Ocean.

94 BLM. "Implement NTL-4A and 43 C.F.R. 3178 Regulations; the 43 C.F.R 3179 and 3162.3-1(J) Requirements of the 2016 Waste Prevention Regulations Are Invalidated." October 22, 2020. https://www.blm.gov/policy/ib-2021-003.

95 BLM. "43 CFR Parts 3160 and 3170 Waste Prevention. Production Subject to Royalties, and Resource Conservation." *Federal Register*, Vol. 87, No. 229, November 30, 2022: 73588. https://www.govinfo.gov/content/pkg/FR-2022-11-30/pdf/2022-25345.pdf.

supportive of NAAQS, such as establishing levels of pollutants that become relevant to state air quality and general compliance with NAAQS in onshore regions. The role of BSEE is typically to ensure that facilities are operating in compliance with BOEM-approved regulations and plans for specific facilities.

While these agencies do not directly regulate GHG emissions, there are GHG-related reporting and requirements built into the offshore regulatory frameworks. As part of the criteria for performing lease sales, BOEM conducts assessments of the life cycle GHG emissions associated with the lease sale and estimates the global difference in GHG emissions from a substitute energy supply source. For operating facilities, BOEM conducts a data collection process with operators every two to four years to estimate criteria pollutant and GHG emissions in a Gulf-wide inventory (2000-2017) and across the OCS (2021 and 2023). Since EPA does not have jurisdiction over most offshore operations, Subpart W reporting under the U.S. GHGRP requires operators to provide summary information from most recently published BOEM data collection process for their assets. With the introduction of the waste emission charge under the Inflation Reduction Act, EPA has proposed an amendment to the GHGRP to allow for operators to provide annual GHG emissions data versus relying solely on data from the most recently published BOEM inventory to be able to reflect upgrades to facilities made since the last inventory year.

BSEE has additional regulations around flaring and venting of gas from offshore platforms, including requirements to request and receive approval for nonemergency flaring and venting activities, duration, and volume limits for emergency situations after which approvals for continued flaring and venting are needed, and metering requirements for flaring and venting at assets that produce more than 2,000 barrels of oil per day. Monthly flaring and venting volume reports are submitted to BSEE and are publicly accessible. A recent study[96] indicated that U.S. offshore requirements around reporting information on intermittent emissions are among the most robust sources of public information of that type globally.

5. Council on Environmental Quality (CEQ)

Compounding authorization of oil and gas activities on federal lands, the OCS, and other projects requiring federal authorization, such as various types of energy infrastructure projects (power plants, transmission lines, pipelines, LNG facilities, and natural gas storage facilities), the National Environmental Policy Act (NEPA) imposes requirements on authorizing federal agencies to consider the potential impacts of proposed actions and inform the public of those impacts. The CEQ, which is within the Executive Office of the President, is responsible for approving federal agency NEPA procedures, providing guidance on NEPA implementation, and facilitating interagency collaboration on environmental matters. CEQ does not have regulatory authority, but its guidance and coordination of other agencies influences environmental decision-making across federal agencies. Notable implications of this process on the oil and natural gas industry can be derived from the Keystone XL pipeline, where the NEPA review process spanned several years, including multiple rounds of environmental assessments and environmental impact statements, evaluating factors such as the potential impacts on water resources, wildlife habitat, and climate change. The project was officially canceled in 2021 by its developer, citing the NEPA review process as a contributing factor.

6. U.S. Coast Guard

Specific to ensuring the safety and security of oil, natural gas, and LNG, the United States Coast Guard (USCG) conducts inspections of transportation vessels to ensure compliance with safety, security, and environmental regulations, promotes safety and prevention of marine accidents that could lead to spills, leaks, and other environmental incidents, coordinates emergency response and spill management, and provides maritime security and traffic management. The International Maritime Organization (IMO), a United Nations agency, sets global standards for

96 Chen, Z., Yacovitch, T.I., Daube, C., Herndon, S.C., Wilson, D., Enoch, S., and Allen, D.T. 2022. "Reconciling Methane Emission Measurements for Offshore Oil and Gas Platforms with Detailed Emission Inventories: Accounting for Emission Intermittency." *ACS Environmental Au.* 3 (2): 87–93. https://doi.org/10.1021/acsenvironau.2c00041.

reducing GHG emissions from ships, including the International Convention for the Prevention of Pollution from Ships (MARPOL), which, among other requirements, includes energy efficiency measures aimed at reducing GHG emissions. The USCG enforces these other agency's standards and regulations, including enforcement of MARPOL for vessels operating in U.S. waters and EPA rules.

7. Interagency (and Cross-Agency) Cooperation

There is an opportunity for the federal departments regulating methane emissions, as described above, to harmonize measurement, methane controls, and policies by coordinating requirements across these rules, while complying with individual agency limitations by statutory authority. This could accelerate the deployment of methane measurement, reduce compliance costs, minimize duplicative compliance and reporting requirements, and improve the comparability and accuracy of data across programs.

The role of advanced methane technologies is a key area for cooperation. The ability for operators to use advanced methane technologies for compliance with LDAR and emissions reporting requirements is a key example where there is not current alignment among different federal agencies, and even within the same agency, for different regulations. As part of NSPS OOOOb and EG OOOOc, EPA included a technology matrix, which scaled the frequency of advanced technology screening based on the instrument detection limit in kg/hr, relative to quarterly OGI. A few months later, PHMSA proposed an alternative technology standard based on a parts per million (ppm) measurement within a specific distance from equipment. A kg/hr standard and a ppm standard are not comparable, as the downwind ppm will vary for the same emissions rate based on meteorological factors like wind direction and speed. Separately, EPA proposed changes to Subpart W for the waste emission charge that excluded alternative technologies as a screening or measurement option for sources like flares or tanks, proposing different types of monitoring requirements than in NSPS OOOOb and EG OOOOc, with the exception of allowing for alternative technologies to be used, particularly by third parties, as part of the new "other large release events" category of methane reporting.

The EPA NSPS OOOOb rulemaking covers a large part of the natural gas supply chain from production, gathering and boosting, processing, transmission, and storage segments, potentially providing approvals from the advanced technology and methodology matrix approaches that can address emissions across other agency rulemakings. EPA's model for integrating advanced methods on an ongoing basis in this proposal rulemaking can serve as a framework for continuous review and approval of advanced technologies and rigorous performance criteria. This process could serve as a clearinghouse that minimizes the need for other agencies to have their own approval process for advanced monitoring and measurement methods and eliminate the need for an applicant to replicate the information already provided to EPA. Agencies with requirements that vary from EPA's requirements can still rely on EPA-approved methodologies coupled with additional performance criteria tailored to the compliance purpose of the other agency's particular program or statute.

With performance standards appropriate for quantification of methane emissions and technology advances noted in Chapter 3, the NSPS approval process could also be relied on for Subpart W reporting and the methane waste emission charge. An advanced technology approach approved by EPA in the final NSPS rulemaking could also be an allowed compliance approach in other federal rules, such as waste gas minimization rules for natural gas production on federal lands from the BLM, DOE's MMRV framework, which could rely on EPA-approved definitions and methodologies as standard benchmarks for monitoring and measurement, and the IRA 45(V) hydrogen tax credit, which could rely on approved measured data approaches as an input to the life cycle assessment required for the credit.

Beyond advanced technologies, there can be unintended consequences associated with misaligned definitions between rules. Within different EPA regulations, a centralized tank battery could be classified as a production site for rules focused on source control and in the gathering and boosting segment for another rule on emissions

reporting, which adds complexity to databases and compliance tracking. In some cases, it could incentivize the development of less complex facilities, with more potential equipment and fugitive components, which is generally misaligned with goals to reduce overall GHG emissions.

To date, there is limited evidence to suggest that such interagency coordination is occurring as each agency is working to finalize their individual rules. The cabinet-level Methane Task Force (WHMTF) that was established by the Biden administration in July 2023 could work to promote such coordination and innovation for emerging technology. By ensuring consistent rules, standards, and practices across programs in other federal agencies, the WHMTF could significantly accelerate the adoption of advanced technologies vital for enabling policies that rely on the carbon-intensity performance of natural gas and avoid conflicting reporting requirements for different programs. Harmonized programs will also promote greater transparency and public confidence in U.S. methane policies.

Misalignment and duplication between rules are also likely to have a disproportionate impact on smaller and marginal well operators who may not have dedicated legal or technical staff to help with interpretation and implementation of complex new regulations. Improved interagency consistency and standardization on regulations would reduce potential confusion among this class of operators, help to improve compliance with regulations, and focus activities on emissions reductions. Given the different staffing levels among smaller and marginal well operators and feedback from the NPC LCO workshops, educational outreach programs by trusted partners like state or regional trade organizations or by state-level regulators would have value to these types of operators. Guidance and assistance with accessing allocated funding for small and marginal operators under grants outlined in the Inflation Reduction Act would be a welcomed inclusion in these outreach activities.

The Global Methane Pledge has a goal of reducing global anthropogenic methane emissions by 30% in 2030, compared to a 2020 baseline. As shown in Figure 1-16, most U.S. methane emissions come from sectors beyond the oil and gas industry, including agriculture (38%), waste (20%), and coal (7%). Meeting national methane reduction goals will require innovative policy development and technology deployment across these sectors. While the need for methane reduction across economic sectors is recognized in the 2021 U.S. Methane Emissions Reduction Action Plan,[97] most actions to date, as highlighted in the 2023 White House Methane Summit,[98] have focused on methane emissions and reduction opportunities in the oil and gas sector. As with the natural gas supply chain, methane emissions from other sectors are expected to have some similar characteristics, like many small-volume emissions sources across a wide geography, and challenges with detection and quantification. In particular, there is likely a pathway to using a subset of technologies developed for methane detection and measurement in the oil and gas sector and applying these approaches to other methane-emitting sectors, while working with those sectors to understand unique needs and challenges. Convening bodies like the White House Methane Task Force could help to facilitate such technology transfer discussions and conversations between different agencies, like DOE and the Department of Agriculture.

RECOMMENDATION 5: *The NPC recommends the White House Methane Task Force work with federal departments regulating methane emissions to harmonize emissions reporting, control requirements, and technology approvals for methane detection and measurement.*

RECOMMENDATION 6: *The NPC recommends that state and local oil and gas trade organizations develop and implement educational programs for smaller operators focused on new*

97 The White House Office of Domestic Climate Policy. "U.S. Methane Emissions Reduction Action Plan." November 2021. https://www.whitehouse.gov/wp-content/uploads/2021/11/US-Methane-Emissions-Reduction-Action-Plan-1.pdf.

98 The White House. "Fact Sheet: Biden-Harris Administration Hosts White House Methane Summit to Tackle Dangerous Climate Pollution, While Creating Good-Paying Jobs and Protecting Community Health." July 26, 2023. https://www.whitehouse.gov/briefing-room/statements-releases/2023/07/26/fact-sheet-biden-harris-administration-hosts-white-house-methane-summit-to-tackle-dangerous-climate-pollution-while-creating-good-paying-jobs-and-protecting-community-health/.

regulatory requirements and access to federal methane mitigation funding, which has been allocated by Congress for this purpose.

C. Voluntary Initiatives

Voluntary initiatives in the United States have made important contributions to deploying advanced detection technology, developing emissions control best practices, and improving emissions reporting methods. This section discusses some key initiatives in the oil and gas sector and offers perspectives on how the impacts of such efforts could be amplified within the United States and globally as countries develop strategies to meet the Global Methane Pledge and other GHG reduction targets.

Participation in voluntary initiatives has potential challenges, including claims from certain stakeholders that such efforts are not universally applied across all operators and may focus on specific elements of a company's GHG emissions profile. Voluntary emissions reduction initiatives are not unique to the natural gas supply chain or the energy sector.

This section is meant to provide an overview of the breadth and types of voluntary GHG reduction programs in the U.S. natural gas industry. Mentioning or nonmentioning of individual programs should not be construed as an endorsement or nonendorsement by the NPC of any particular initiatives.

1. Emissions Reporting

As discussed in prior sections, the EPA administers an annual greenhouse gas reporting program, known as the GHGRP, that requires emissions reporting across the natural gas supply chain for facilities that exceed 25,000 metric tons of carbon dioxide equivalent emissions. Different facility definitions apply for each supply chain segment, but facilities are generally geographically aggregated, like emissions from a production or distribution facility, versus an individual asset within a segment. A number of voluntary initiatives have been developed to augment aspects of required federal reporting or to move toward more measurement-informed reporting methodologies.

For most oil and gas industry assets, the most common GHG emissions are carbon dioxide and methane emissions. Carbon dioxide emissions are typically concentrated at stacks (i.e., single points) throughout a facility and correlated with combustive fuel use. Fuel use is often tracked for a variety of regulatory and financial purposes. By comparison, methane emissions often occur from many dispersed sources. Methane emissions have typically been estimated using standardized emissions factors developed by the EPA because measuring the vast numbers of sources has not historically been possible. Under this emissions-factor-based methodology, an activity or equipment count (e.g., number of pneumatic controllers) is multiplied by an emissions factor for a particular source or activity (e.g., emissions per controller per hour). These factors are developed based on research, engineering designs, and field studies. For example, the EPA GHGRP provides factors to estimate equipment leak emissions from oil and gas wellheads based on previous field-measurement studies. To put the scale of sources into perspective, there were approximately 937,000 producing wells, 480,000 separators, and 1.8 million methane-emitting pneumatic controllers in the United States in 2020. Challenges with methane reporting and measurement are described in depth in Chapter 3.

a. Reporting Programs that Augment Traditional Methane Reporting Methods

Some corporations have internal GHG reporting protocols that augment GHGRP reporting requirements by including additional sources that are not required and/or even reportable under the specific categories defined by the GHGRP. Typically, these programs are based on requirements of the GHG Protocol,[99] which is a corporate GHG reporting standard developed by the World Resources Institute and the World Business Council for Sustainable Development. It is important to note that the GHG Protocol is more principles based than the GHGRP. The GHG Protocol provides boundaries for corporate emissions estimation practices but does not typically define precise calculation methods or equations defined under regulatory programs like the GHGRP.

99 Greenhouse Gas Protocol. 2019. "Greenhouse Gas Protocol." https://ghgprotocol.org/.

Some organizations, like One Future, have written emissions reporting protocols that standardize reporting for additional methane emissions sources by supply chain sector that are not elements of reporting under the GHGRP. Under the One Future protocol, these additional sources, like vessel blowdowns or drilling emissions in the production sector, are estimated based on emissions factors and activity data counts and added to methane emissions estimates for categories covered under the GHGRP. One Future also includes segment-specific goals among its membership to ensure a methane loss rate of less than 1% along a theoretical supply chain from production to distribution composed of its member companies. The Natural Gas Sustainability Initiative (NGSI) builds off the One Future methane emissions estimation protocol to provide guidance on coproduct allocation of emissions and standardized emissions intensity disclosures by supply chain segment. NGSI was developed by the Edison Electric Institute and the American Gas Association, which are trade associations for the major natural gas purchasers (utilities and local distribution companies), to have a consistent data template for obtaining methane information from gas suppliers. OGCI also has an emissions reporting protocol that includes consistent methane emissions categories and is more targeted for global operations, where standardized regulatory reporting like the GHGRP does not exist. Standardization of sustainability information requests can help with efficiency at companies receiving those requests as well as supporting liquidity in markets like natural gas where ability to provide buyer-specific sustainability data requests may be a barrier to some transactions.

Life cycle assessment, which is described in depth in Chapter 4, is a potential alternative to the GHG Protocol philosophy that draws a distinction between sources inside and outside the control of a firm. Life cycle assessment requires additional information on supply chain segment linkages, which is typically not available in current regulatory and corporate reporting. Some emerging policies, like border carbon adjustment mechanisms and the 45V tax credit for the production of clean hydrogen, would require this type of information.

b. Measurement-Informed Reporting

Initiatives discussed in the previous section have made important contributions to the standardization of emissions reporting data, to the development of targets for companies, and for increasing knowledge of methane emissions issues across the supply chain. Over the last several years, stakeholder and regulatory agencies' expectations have begun to shift away from methane emissions reporting solely based on emissions factors toward discussions on how to include more measurement within reporting to address two types of concerns. First, multiple field-measurement campaigns for methane emissions have noted higher overall emissions than are estimated from emissions-factor-based methods, which are often attributed to higher-emitting sources that may be routine, episodic, or intermittent in nature.[100] From an emissions reporting perspective, this would translate into a concern that actual emissions across the industry may be larger than estimates made with traditional regulatory reporting methodologies. However, care should be taken not to extrapolate industry-wide conclusions to a specific operator or site. Second, there is concern that certain emissions factors, such as methane slip from lean-burn engines, may not be accurately accounted for in current regulatory emissions factors, which could lead to suboptimal abatement prioritization for sources.

Several measurement-informed initiatives have developed to provide different types of structures to address these expectations. Although few companies today are fully utilizing measurements in their corporate or regulatory reporting, important case studies and pilots on both the technology and protocol implementation sides may help scale these types of efforts. Measurement-based protocols rely heavily on the use of methane measurement instrumentation at scale, which has only become possible after completion of programs like ARPA-E MONITOR and SCALEUP, as well as further industry refinement efforts to ensure that technologies were ready for broader deployment. At the same time, the development of third-party

100 U.S. National Academies of Sciences, Engineering, and Medicine. 2018. "Improving Characterization of Anthropogenic Methane Emissions in the United States." National Academies Press. Washington, D.C. https://doi.org/10.17226/24987.

monitoring campaigns, like the Environmental Defense Fund (EDF) Permian MAP project, provides additional data points for conducting methane measurement with scale. The development of measurement-informed inventories is an active area of interest for state, federal, and global policymakers.

The Oil and Gas Methane Partnership 2.0 (OGMP2.0) is a multistakeholder initiative launched by the UNEP and the CCAC to develop measurement-informed reporting for the upstream, midstream, and downstream segments of the global oil and gas industry. More than 100 companies have signed on to the initiative. The intent of OGMP2.0 program is to increase the quality and specificity of methane emissions information used in data reporting, which are described as levels between 1 (lowest data quality and specificity) and 5 (highest). In its current state, the GHGRP is a mixture of Level 3 (generic emissions factors for individual source types) and Level 4 (specific emissions factors and activity data for individual sources), depending on the exact source. Proposed changes to the GHGRP by EPA may offer a pathway for more source-specific measurement to be included, but the programs are not aligned on all requirements. Level 5 requires technology-based emissions comparison of the Level 4 inventories as an additional confirmation step for a portion of the assets in a company. According to the International Methane Emissions Observatory at UNEP,[101] average reporting under OGMP2.0 is currently occurring at Level 3, and engineering calculations appear to be the preferred method for sources that have reached Level 4 reporting. OGMP2.0 has been active for three years with emissions reporting, and there is an expectation that reporting levels should increase over time as companies work toward their three-year and five-year plans for reaching at least Level 4 for operated and non-operated assets, respectively. Information is currently disclosed at the company-total level under OGMP2.0, which makes it different from asset-level reporting in the U.S. and granularity for natural gas certification programs that are addressed later in this section.

In collaboration with 30 sponsors from U.S.-based companies, technology providers, and nongovernmental organizations, GTI Energy launched the Veritas program, which aims to develop protocols to calculate segment-specific, measurement-informed methane inventories and intensities across different natural gas supply chain segments. After sponsors tested draft protocols, the initial versions of the protocol were released in 2023.[102] The foundation of the protocols is guidance on conducting field measurements of methane emissions, a protocol for incorporating information from those measurements into an emissions inventory, and guidelines for developing methane intensities across the supply chain and assuring the use of the Veritas protocol. The protocol indicates that some sources are best measured while others are best estimated from engineering estimates or emissions factors. While there are currently limited examples of public disclosures with the Veritas protocols, potentially due to the newness compared to other initiatives, two natural gas certification programs have incorporated Veritas as an option for quantifying methane emissions[103] and OGMP2.0 is considering a Veritas-based option for reporting.[104]

Because of the Global Methane Pledge commitment by the United States to move toward using the highest tier IPCC good inventory methodologies, there is policy interest within the government to improve national methane inventories by increasing the use of direct measurements to inform emissions estimates. As a practical matter, EPA manages the collection of GHG information from emitters through the GHGRP and the development of the GHGI, which is the official

101 U.N. Environment Programme. 2022. "An Eye on Methane: International Methane Emissions Observatory 2022." Nairobi. https://wedocs.unep.org/bitstream/handle/20.500.11822/40864/eye_on_methane.pdf?sequence=3&isAllowed=y.

102 Veritas, GTI Energy. "Accelerating Efforts to Reduce Global Methane Emissions." Veritas Protocols. February 2023, December 2023, February 2024. https://veritas.gti.energy/.

103 Highwood Emissions Management. "An Overview of Voluntary Emissions Reduction Initiatives for the Oil and Gas industry." September 2023. https://highwoodemissions.com/wp-content/uploads/2023/09/Highwood_Vi3_vl7_CompressedSmall.pdf.

104 Brennan, Sean. 2024. "Methodology Announced for Veritas and OGMP 2.0 Methane Emissions Reduction." GTI Energy. February 29, 2024. https://www.gti.energy/methodology-announced-for-veritas-and-ogmp-methane-emissions-reduction/.

Program	First Reporting Year	Sponsoring Government Agency	Data Reviewing Organization	Type of Program	Primary Focus	Level of Public Data Disclosure	Role of Calculation and Measurement
US GHGRP	2010	EPA	EPA	Regulatory	Information to develop the GHGI	Source and facility-level emissions at the asset and source level	Defined calculation methods with measurement-based options for some sources
One-Future	2017	None	Consultants for OneFuture	Voluntary	Corporate Reporting	Member company average by segment	Augmentation of reporting for certain GHGRP sources
OGMP2.0	2021	European Commission	UNEP	Voluntary	Corporate reporting	Global corporate totals	Flexibility for calculation methods with measurement requirements for highest reporting tiers (Levels 4 & 5); Level 4 requires source-specific measurements, which would be independently verified with Level 5 measurements
Veritas	2024	None	Third-Party assurance	Voluntary	Asset-level reporting	Protocols discuss public-facing information disclosure at the asset-level	Field-based measurements are required for using the protocol, with a focus on larger emissions sources. Smaller sources may be reported with emissions factors.

Table 1-5. *Examples of Regulatory and Voluntary Methane Reporting Programs*

record of U.S. GHG emissions submitted to the UNFCCC annually. Thus, improvements to national inventory estimates will necessarily need to flow through GHGRP rulemaking to update utilization of specific methodologies that require considerations. The rulemaking process considers the cost and ability of companies and regulators to implement new standards. In 2022, EPA proposed[105] some updates to GHGRP reporting segments, including Subpart W for the oil and gas sector, that, if finalized, would increase the types of emissions reported, including a 250 metric ton CO_2e per event threshold for emissions from upstream segments not already documented in other source categories. In 2023, EPA published a new proposal[106] superseding the 2022 proposal and to support implementation of the Methane Emission Reduction Program under the Inflation Reduction Act. While many stakeholders agree on the need to improve methane emissions reporting, it should be noted that current EPA GHGI methods comply with the highest IPCC tiers for the oil and gas sector, which is not true for many other national inventories developed by other countries.

105 EPA. "40 CFR Parts 9 and 98 Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule." Proposed rule. *Federal Register*. Vol. 87, No. 118, June 21, 2022: 36920. https://www.govinfo.gov/content/pkg/FR-2022-06-21/pdf/2022-09660.pdf.

106 EPA. "40 CFR Part 98 Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems." *Federal Register* Vol. 88, no. 146, August 1, 2023: 50282: https://www.govinfo.gov/content/pkg/FR-2023-08-01/pdf/2023-14338.pdf.

Improved and consistent measurement of methane emissions from oil and gas operations would support a variety of voluntary and regulatory initiatives and improve confidence in numbers, which is an important criterion for market-based policy options, such as carbon pricing mechanisms and premiums for lower-carbon-intensity supply options. At the same time, methane measurement is challenging to accomplish given the diversity and spread of the U.S. natural gas sector, and technology sets for measurement that often provide snapshot estimates. Multistakeholder agreement guidelines on transparent, accountable, and verifiable measures of GHG content would be beneficial to prevent duplication of efforts to develop such a standard by different federal and state agencies or individual gas buyers.

FINDING 23: **Improvement of methane measurement and reporting is expected to be fundamental to a variety of voluntary, regulatory, and market-based programs in the United States.**

FINDING 24: **Methane measurement and reconciliation at scale remains a technical challenge as companies deploy technology and trial quantification and reconciliation protocols. Several existing voluntary initiatives have proposed different approaches.**

RECOMMENDATION 7: ***The NPC recommends that the natural gas industry actively resource voluntary efforts to develop and test measurement-informed methane reporting protocols based on application of advanced technology.***

RECOMMENDATION 8: ***The NPC recommends a one-year multistakeholder group led by DOE and EPA develop recommendations on incorporating company-specific, advanced technology measurements into Greenhouse Gas Reporting Program Subpart W reporting.***

2. Best Practice Sharing Organizations

The development and deployment of best practices has been a key feature of multistakeholder partnerships. These partnerships can include combinations of oil and gas industry operators, government agencies, and nongovernmental organizations. While voluntary information sharing programs will not include every company in a sector, there have been some notable achievements in the United States related to the development of best practices that have wide deployment across the industry and to the provision of fundamental information that has been needed to understand emissions reduction options in the sector. As new technologies to detect and measure methane emissions are developed, initial deployment is often at facilities owned by operators participating in voluntary programs. In addition to academic research programs, field deployment of technologies through voluntary initiatives helps accelerate technology development.

Historically, the development and sharing of emissions reduction case studies by operators has been a key feature of learning-driven partnerships to share what has been successful for a peer company in a specific type of asset. Such programs can reduce the deployment learning curve for similar operators and lead to emissions reductions. In the United States, the EPA started the Natural Gas STAR Program in 1993 as a forum for operators to share innovative and voluntary actions by the oil and gas industry to reduce methane emissions, and the program website has 72 publicly available case studies for different methane reduction technologies across different segments in the natural gas industry. Through forums like the Global Methane Initiative, EPA has worked to export best practices and technologies to partner countries and organizations globally. The methane reduction opportunities and economic analyses in the Natural Gas STAR Program remain one of the few sources of information on this topic and continue to be used by a variety of organizations, including the IEA methane abatement cost model. In the 2021 GHGI, EPA estimates that the Natural Gas STAR Program provided direct methane reductions of approximately 7 MMT CO_2e, which is approximately 3% of total methane emissions in the sector. In 2019, EPA sunset the Natural Gas STAR Program and began the Methane Challenge Program, which added an increased focus on reporting of emissions reductions.

Organizations like the Methane Guiding Principles, which includes 27 signatory oil and gas companies and 21 supporting organizations from civil society, have included projects to aggregate and provide tools for updated economic assessment of emissions reductions opportunities. These projects and tools inform training and best practice analysis for companies and regulators as reducing methane emissions has become a focus within global GHG mitigation discussions.

The Environmental Partnership (TEP), which currently has more than 100 members and includes operators with more than 70% of U.S. onshore production, has built on the historic model of best practice information sharing to focus on specific actions to reduce methane and VOC emissions. TEP includes environmental performance programs for pneumatic controllers, manual liquid unloadings, LDAR, compressors, pipeline blowdowns, and flare management. Participating companies work to implement defined emissions abatement actions over specific phasing periods and complete an annual report. From 2018–2021, TEP companies completed more than 1.2 million leak detection surveys and replaced more than 51,000 gas-driven controllers. TEP includes workshops at both the national level and basin levels to discuss learnings and best practices.

For the transmission and storage segment of the supply chain, the Interstate Natural Gas Association of American has developed a list[107] of methane and other GHG reduction actions for its members in the sector. For methane, best practices are included for LDAR, pipeline blowdowns, pneumatic controllers, and compressor seals. Carbon dioxide reduction is focused on energy efficiency improvements and evaluating electrification at compressor stations.

Additional partnership models include research consortia that cofund activities to improve understanding of emissions and abatement options. In 2012, EDF began a series of 12 studies partnering with relevant segment operators and universities to conduct research aimed at better estimating the amount of methane emissions from U.S. onshore operations and updating emissions factors for key sources. The Collaboratory to Advance Methane Science includes six sponsors from across the natural gas supply chain in the United States and has funded fundamental research on topics like methane emissions measurements from LNG shipping, spatially and temporally resolved modeling tools for basin-scale methane emissions, and early work on multioperator aerial detection approaches. In 2021, Cheniere announced[108] a partnership with two academic institutions and five producers in its supply chain to implement quantification, monitoring, reporting, and verification, which has resulted in several peer-reviewed publications. In 2023, the University of Texas at Austin announced the formation of Energy Emission Modeling and Data Lab with sponsorship from three U.S. companies to develop new tools for methane accounting, with a particular focus on measurement and supply chain reporting.

Research consortia models include important contributions from all parties. Operators often provide site access, substantial data, and funding to the programs to support the development of actionable research and learn more about key emissions sources. Some research programs have chosen models that exclude operator involvement, which lead to trade-offs around operational understanding of measurement information and the ability to translate the measurements into specific emissions reduction actions.

As other countries move toward greater understanding of their methane emissions and reduction options in support of the goals of the Global Methane Pledge, development of local or regional best practice sharing and research efforts could support these goals. Emissions sources, considerations, and technology options are likely to vary across geographies and local or regional efforts may be best placed to develop actionable programs.

Best practice sharing is likely to increase in importance, particularly for smaller and marginal

107 Interstate Natural Gas Association of America. "2021 Greenhouse Gas GHG Emissions Commitments." November 16, 2021. https://ingaa.org/2021-ghg-emissions-commitments/.

108 Cheniere Energy, Inc. "Cheniere Announces Collaboration with Natural Gas Suppliers and Academic Institutions to Quantify, Monitor, Report and Verify GHG Emissions." June 10, 2021. https://lngir.cheniere.com/news-events/press-releases/detail/220/cheniere-announces-collaboration-with-natural-gas-suppliers.

operators, as the suite of federal methane regulations begins to take effect. There are potentially models informed by past technology sharing programs, like the 1990s and 2000s efforts by the Petroleum Technology Transfer Council (PTTC) to share technologies with independent U.S. producers that were focused on cost, operating efficiency, and increased hydrocarbon recovery from existing resources. PTTC included models around regional workshops in production regions and partnerships with state agencies, local trade associations, and regional universities with topical expertise that was funded by DOE grants and fees from workshop attendees. Based on workshops with LCOs that were hosted as part of this NPC study, a similar knowledge-sharing program with a focus on GHG reduction technologies and in partnership with entities like local oil and gas trade associations would be welcomed by smaller and marginal operators. Retired oil and gas industry workers would be an important talent pool for models like PTTC to draw on.

RECOMMENDATION 9: *The NPC recommends the development of education and best practice sharing programs and materials by local oil and gas associations and state regulators to increase smaller and marginal operator access and understanding of technical, information technology, and operational best practices to detect and reduce GHG emissions.*

RECOMMENDATION 10: *The NPC recommends revitalizing or starting up an organization in the model of the Petroleum Technology Transfer Council to transfer GHG emissions reduction technology and best practices to smaller and marginal well operators.*

3. Natural Gas Certification Programs

Natural gas certification programs were designed to allow tracking of various criteria, including methane and GHG emissions, from the natural gas operator to the end-use customer, analogous to the renewable energy certificate program at EPA. While different programs have focused on various criteria, several prevalent certification programs in the United States focused on methane emissions, given historical challenges with measurement and reporting at-scale. As a result, several of the programs have historically used independent, subject matter expert assessment of company methane management programs and technology deployment as a proxy for measured methane intensity. This third-party assessment model is now shifting toward measurement-informed methane inventories and certification of other GHG and non-GHG performance criteria. Natural gas certification programs are built around end users, governments, and regulators valuing emissions reductions and other metrics and the ability of financial and market instruments to price and reward low-emissions-intensity gas with credible emissions attributes. So far, these markets remain developing.

DOE is currently working with agencies from other global gas-producing and exporting countries to develop an MMRV framework, particularly for export-oriented supply chains, that may include elements of certification criteria, accreditation processes, and data transparency that may build on elements of different certification and measurement programs.

The most well recognized natural gas certification programs have been largely concentrated in North America and in the production sector, although most vendors offer certification options for different supply chain segments. There are similarities and differences between these voluntary frameworks that are summarized in more detail by other organizations, like Highwood Emissions Management.[109] Several programs generate certificates for one or more environmental attributes that are often housed on registries, which are common instruments for tracking environmental details where the chain of custody is not direct or differentiating details are not otherwise recorded through contracts with the physical commodity, such as renewable electricity and low-carbon fuels.

To suit the needs of stakeholders and natural gas buyers around emissions transparency, harmonization of common elements of certification

109 Highwood Emissions Management. "An Overview of Voluntary Emissions Reduction Initiatives for the Oil and Gas industry." September 2023. https://highwoodemissions.com/wp-content/uploads/2023/09/Highwood_Vi3_vl7_CompressedSmall.pdf.

(third-party audits, registry tracking, transparency) may be beneficial to increase access and adoption of differentiated gas. While third-party assurance activities have likely been expanded via North American companies seeking certification for differentiated gas programs, it should be noted that some companies have included third-party GHG verification for voluntary emissions disclosures, such as in sustainability reports, and for emissions verification in areas like California, with cap-and-trade systems. Thus, there are several methods for emissions data verification.

a. Market Conditions for Certified Gas in the United States

Some natural gas buyers and end users have indicated an interest in purchasing certified gas products for a variety of reasons, including improved assurance around Scope 3 emissions within their supply chain for tracking progress on corporate net zero GHG emissions goals or potentially for access to tax credits or import markets that may require such information in the future. Many of the transactions between sellers, marketers, and buyers are currently individual, bilateral agreements and considered proprietary information, therefore tracking the actual value in the marketplace is currently largely unavailable. Trading platforms and marketplaces are currently attempting to provide pricing benchmarks, and the range of value for the Methane Performance Certificate, one option on the market, was between 1 and 5 cents per MMBtu in 2022, based on data from Platts.[110] The North American Energy Standards Board has developed a Certified Gas Addendum for its base contract to allow for increased transactability in the certified gas market.

There are different views on how future developments in gas certification could be a feature of markets. First, differentiated pricing, either a premium or discount, around specific emissions intensity performance or Environmental, Social, and Governance criteria could provide a financial signal for operators hitting certain benchmarks or to understand how the market would value additional improvements. A recent study[111] pointed to the potential of differentiated gas markets but concluded that it was unable to ascertain if current markets were simply rewarding existing differentiation versus incentivizing additional improvements in methane or carbon intensity. Second, markets could use certifications as a screening criterion for sales or entry of natural gas products (i.e., a floor for market access). While such a program may provide additional assurance, it is not clear that it would continue to reduce emissions or improve performance beyond minimum requirements and, in a liquid trading market, could potentially redirect flows for screened-out products to other buyers without such programs in place.

Many of the initial natural gas certification efforts in the United States have been in the production sector, where the producer pays for the certification process. The first deal between Southwestern Energy and New Jersey Natural Resources occurred in 2017.[112] S&P Global[113] estimates that ~30% of U.S. natural gas production was certified in 2022, primarily from dry gas producers in Haynesville and Appalachia. It should be noted that newer, unconventional dry gas production may be advantaged in current certification frameworks due to lower compression and gas treatment needs to ensure that the gas is up to long-distance transmission specifications, compared to other types of assets, which may partially explain the early adoption by this subset of producers.

Major domestic buyers have not been as quick to commit to buying certified gas, but there are emerging examples of purchases. Many of the largest buyers—local gas distribution companies or power utilities—purchase gas on behalf of end users; these utilities are regulated by public utility

110 S&P Global. "Future Energy Outlooks Special Report." August 18, 2022. https://www.spglobal.com/_division_assets/images/special-editorial/inflation-reduction-act/generaloverview-1.pdf.

111 Garg, S., Boz, D.E., Gilbert, B., and Crompton, J. 2023. "A Critical Review of Natural Gas Emissions Certification in the United States." *Environmental Research Letters.* 18 (2): 023002–2. https://doi.org/10.1088/1748-9326/acb4af.

112 Hart Energy. "Going for the Green: Responsibly Sourced Gas." February 18, 2022. https://www.hartenergy.com/exclusives/going-green-responsibly-sourced-gas-198840.

113 S&P Global. "Future Energy Outlooks Special Report." August 18, 2022. https://www.spglobal.com/_division_assets/images/special-editorial/inflation-reduction-act/generaloverview-1.pdf.

commissions and bound to procure the lowest-cost supply options on behalf of their customers. Although some utilities and public utility commissions are actively developing frameworks to support cost recovery for certified gas purchases, the number of stakeholders, complexity of the certifications available, the number of contracts, and scale of buyers signals a drawn-out timeline for national-scale efforts. Despite these challenges, individual utilities are issuing requests for offers and procuring certified gas. Commissions in Michigan and several other states are considering requests for cost recovery as part of requests for proposals from utilities they regulate for certified gas, and New York has approved cost recovery for a utility. State legislatures, including Tennessee and Virginia, have passed laws designed to support low-emissions natural gas to meet various climate initiatives. In other cases, buyers have been able to secure certified gas as the lowest cost option in states where cost recovery is not available.

There is not a single perspective on certified gas markets among all U.S. gas buyers as some regulated utilities do not have approval to pay above market rates on contracts. Some companies have expressed hesitancy to undertake the regulatory proceedings that would be necessary to sign medium- to long-term contracts because evolving standards may mean that a higher-priced, low-emissions product offering today is considered status quo under future regulations, such as those discussed in sections of this report on federal regulations. The lack of standardization of value, and how to evaluate and compare different certification regimes, represents another hurdle for potential buyers and regulators in this developing market.

The certified gas market could align over time with gas marketing activities by standardizing quantifiable emissions attributes separate from the gas molecule. This shift would reduce the complexity of the certification framework to focus on fewer elements that could be factored into gas transactions and more easily assessed by buyers, such as measured methane or carbon intensity. Reduction of programmatic complexity could also reduce the overall costs of administering such programs. A simpler and more quantitative approach may help to promote policy changes needed for the gas buying community.

4. LNG Supply Chain CI Estimation Programs

While piped gas mainly serves a domestic market in the United States, LNG is a globally traded commodity, similar to oil. As LNG importers like the European Union, Japan, and Singapore, have begun to consider the embedded emissions within imported products and fuels versus only emissions within their specific geographic boundaries, several initiatives have emerged to quantify the methane and carbon intensity associated with LNG cargoes or supply chains to better understand and potentially differentiate the market.

Developing tools to estimate the methane and carbon intensity of LNG supply chains is a complicated endeavor that will require advancements in models and tools. Broadly, the technical building blocks[114] for such programs would include elements such as measurement-based emissions estimates, data-quality metrics, independent verification frameworks, and supply chain synthesis tools. Relative to many other large LNG exporters, the United States is in a unique position.[115] Many operators in the United States have experience with public regulatory GHG reporting, state and federal regulations, certification programs, and third-party measurements, which have overwhelmingly been concentrated in the United States. However, U.S. natural gas supply chains are incredibly complex in terms of the number of sites and assets involved in production and transport, which makes it nearly impossible to identify the origin or exact path of specific gas molecules to an LNG plant. Practically, this means that intensity estimates will need simplified models of individual natural gas supply chains or stacked

114 Ravikumar, A.P., Tullos, E.E., Allen, D.T., Cahill, B., Hamburg, S.P., Zimmerle, D., Fox, T.A., et al. 2023. "Measurement-Based Differentiation of Low-Emission Global Natural Gas Supply Chains." *Nature Energy*. 8 (11): 1174–76. https://doi.org/10.1038/s41560-023-01381-x.

115 Oxford Institute for Energy Studies. "Greenhouse Gas Emissions from LNG Trade: From Carbon Neutral to GHG-Verified." September 2022. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2022/09/Insight-124-Greenhouse-Gas-Emissions-from-LNG-Trade.pdf.

asset-level certifications to provide estimates for specific LNG export routes. By contrast, many LNG projects outside the United States have simpler value chains with single or limited numbers of producing fields and infrastructure pathways that may make tracing easier. This is contrasted with relatively less experience with collecting GHG information and studying methane emissions.

The development of transparent, accountable, and verifiable measures of CI would not only benefit U.S. GHG reduction goals, but also potentially benefit U.S. natural gas producers and LNG exporters in their marketing of U.S.-sourced natural gas and LNG against suppliers adhering to less rigorous emissions standards. If well executed, the DOE MMRV framework that is under development with multiple partner countries could help to drive some of this standardization in non-U.S. operations and allow for more comparability in the LNG marketplace. Several of the service providers for asset-level certification have also begun to offer products that link together asset-level emissions and track GHG emissions across supply chains. The rest of this section will focus on specific initiatives that have attempted to estimate the methane and carbon intensity for LNG cargoes, including emissions from different supply chain stages.

In 2022, Cheniere became the first LNG exporter from the United States to provide an estimated GHG intensity with the Cargo Emissions (CE) Tags program, which provided estimates of the life cycle GHG emissions for each cargo of LNG produced at its Sabine Pass and Corpus Christi liquefaction facilities.[116] The CE Tags are calculated using a peer-reviewed modeling framework[117] and supplier-specific GHG data.

In 2021, Chevron, Qatar Energy, and Pavilion Energy published a quantification and reporting methodology[118] to produce a statement of GHGs for delivered LNG cargoes that can be assured by third parties. Of note, public-domain utilizations of the protocol have included LNG supply chains where production through liquefaction occurs in less complex supply chains than the United States'. The methodology could cover complex supply chains like the United States' but would encounter the needs for supplier-specific information and to manage the complexities noted earlier in this section.

The International Group of Liquefied Natural Gas Importers (GIIGNL) is an international association of mostly LNG buyers. It is developing a framework[119] for companies to follow in developing and verifying an estimate of the delivered GHG intensity of a cargo of LNG. The framework states that GHG emissions should be provided by the entity in control of each stage of the supply chain, based on established standards and methodologies. Unlike the protocols mentioned above, the GIIGNL framework is closer to a set of principles than a detailed calculation methodology. Notably, the GIIGNL framework also gives guidance on transparency around the utilization of offsets as part of the cargo GHG intensity statement.[120]

Thus far, all the steps taken by companies to report LNG cargo emissions have been based upon proprietary systems, although some have included academic or third-party assurance of the emissions information. The DOE has begun partnerships with several countries in the Asia-Pacific region to help with LNG methane and carbon-intensity accounting[121] and the creation of

116 Cheniere. "2022 Corporate Responsibility Report." 2023. https://cheniere.s3.amazonaws.com/media/2022-Corporate-Responsibility-Report.pdf.

117 Roman-White, S.A., Littlefield, J.A., Fleury, K.G., Allen, D.T., Balcombe, P., Konschnik, K.E., Ewing, J., Ross, G.B., and George, F. 2021. "LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting." *ACS Sustainable Chemistry & Engineering*. 9 (32): 10857–67. https://doi.org/10.1021/acssuschemeng.1c03307.

118 Chevron Policy, Government and Public Affairs. "Pavilion Energy, QatarEnergy and Chevron Launch GHG Reporting Methodology for Delivered LNG Cargoes." November 17, 2021. https://www.chevron.com/newsroom/2021/q4/pavilion-energy-qatarenergy-and-chevron-launch-ghg-reporting-methodology-for-delivered-lng-cargoes.

119 International Group of Liquefied Natural Gas Importers. "MRV and GHG Neutral LNG Framework." November 2021. https://giignl.org/wp-content/uploads/2021/11/MRV-and-GHG-Neutral-Framework.pdf.

120 Oxford Institute for Energy Studies. "Greenhouse Gas Emissions from LNG Trade: From Carbon Neutral to GHG-Verified." September 2022. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2022/09/Insight-124-Greenhouse-Gas-Emissions-from-LNG-Trade.pdf.

121 DOE. "Joint Statement on Accelerating Methane Mitigation from the LNG Value Chain." August 16, 2023. https://www.energy.gov/articles/joint-statement-accelerating-methane-mitigation-lng-value-chain.

a framework focused on natural gas supply chain MMRV[122] with approximately 20 international government partners. Consistent MMRV and improved data accessibility could allow for more direct comparisons between the CI of different global supply options, although there is future work needed to reach this state.

FINDINGS 25-30:

- **25:** Natural gas certification programs are one option for third-party review of GHG information, particularly for methane emissions.
- **26:** Natural gas certification programs with strong monitoring, reporting, and verification standards offer one potential mechanism for tracking emissions associated with product flows across the natural gas supply chain.
- **27:** The market-based pricing elements remain in development for a variety of factors, including concerns that differentiation between molecules will be reduced via methane regulation, although there are some early examples of public utility commission purchases in the marketplace.
- **28:** The protocols for the global LNG market appear more focused on overall GHG intensity of delivered LNG cargoes versus protocols in the U.S. certified gas market that are more narrowly focused on methane performance, particularly in the production sector.
- **29:** There are several competing protocols with different geographic advantages and proprietary systems in the LNG foot printing space. Simpler tools would be a benefit to U.S. natural gas and LNG markets.
- **30:** DOE has launched a measurement, monitoring, reporting, and verification (MMRV) program with a stated goal of improving MMRV across global gas markets, which may help to improve comparability across programs.

RECOMMENDATION 11: *The NPC recommends that the DOE measurement, monitoring, reporting, and verification program carefully consider key features and learnings from existing natural gas certification and LNG cargo tag programs and consult stakeholders with relevant expertise.*

5. Company Voluntary Actions and Pledges

Since the Paris Agreement in 2015, there has been a marked increase in the number of announcements of GHG reductions goals, pledges, and ambitions, including from companies in the U.S. natural gas supply chain. Corporate GHG emissions reduction goals are commonly taken together with additional commitments for increased transparency and disclosure of emissions. Across companies, setting emissions reduction targets and ambitions can differ in definition and detail, including: emissions scope (i.e., Scope 1, 2, and 3), business region or segment (i.e., an upstream-only or North America region goal), timeframe of goals with interim targets (i.e., 2030 and/or 2050 targets), GHG (carbon dioxide, methane emissions, or all GHG gases), and metric definition (i.e., emissions reduction goals in absolute or intensity terms, year benchmarked against, method(s) for reported baseline, and target emissions inventories).

a. Overall Pledges from the U.S. Natural Gas Sector

For companies operating in the oil and natural gas sector, the pressure to make emissions reduction commitments is particularly unique with increased scrutiny over emissions reported and external skepticism over targets and initiatives. Additionally, commitments or ambitions to net zero GHG emissions are a complex consideration given the sector's business model depends on the production and consumption of fossil fuels. However, this has not prevented companies in the sector from announcing net zero pledges. Of the 33 public U.S. companies tracked in the Net

122 DOE. "Greenhouse Gas Supply Chain Emissions Measurement, Monitoring, Reporting, Verification Framework." Updated March 15, 2024. https://www.energy.gov/fecm/greenhouse-gas-supply-chain-emissions-measurement-monitoring-reporting-verification-framework.

Zero Tracker database, and categorized as part of the fossil fuel sector, 24 (or 73%) companies have some form of emissions reduction commitment, which is higher than the average of 55% of all publicly traded companies.[123] A 2019 Columbia University Center on Global Energy Policy (CGEP) survey[124] of 15 publicly listed U.S. upstream oil and gas companies found that 11 companies supported a net zero GHG emissions goal by 2050, but that the forms of the goals or ambitions were not identical. Within the sector, some companies also include near-term (2025 or 2030) targets around the subset of Scope 1 emissions associated with flaring or methane emissions, generally to signal early prioritization for the emissions reductions from these sources.

Furthermore, corporate net zero GHG pledges are increasingly examined by external stakeholders for additional detail on short- and medium-term strategies and pathways to meet longer-term goals. Due to the increased scrutiny on the sector and the outsized potential impact the sector can have on emissions reductions, company pledges in the sector are characterized by additional emissions reduction commitments that are more granular in detail in terms of targeting specific GHGs, scope of emissions, specific operational practices, and shorter timelines for targets. The 2022 CGEP report found that all companies surveyed had committed to short-term GHG emissions reduction targets by 2025 and that most companies surveyed had committed to zero routine flaring by 2030 and specific methane emissions intensity reduction targets. As of 2022, several companies[125] within the World Bank Zero Routine Flaring Initiative have reported that they have achieved zero routine flaring, but more work is needed to achieve zero routine flaring globally and work toward continued reductions in other types of flaring.

123 Based on NPC analysis of information in the Net Zero Tracker Database (https://zerotracker.net/) in summer 2023.

124 Center on Global Energy Policy at Columbia University. "ESG Investing and the U.S. Oil and Gas Industry: An Analysis of Climate Disclosures." April 12, 2022. https://www.energypolicy.columbia.edu/publications/esg-investing-and-us-oil-and-gas-industry-analysis-climate-disclosures/.

125 The World Bank. "Zero Routine Flaring by 2030 Reporting." n.d. https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/reporting.

Longer-term pledges from the sector typically rely on varying degrees of offsets, technology development, policy changes, and other factors in defining a pathway to meet net zero GHG emissions targets or ambitions. While some stakeholders view this ambiguity negatively, there is also a real opportunity for the industry to be involved in the development of scaled solutions that may reduce GHG emissions that are largely the same types of solutions that are needed for societal GHG emissions reduction goals. As governments around the world, including the United States, develop their GHG reduction plans for midcentury or interim milestones, there remains an important role for public-private partnership to develop the needed solutions for GHG reduction and abatement.

Many companies that operate in the U.S. natural gas sector are also global companies that, at any given time, have more opportunities for global investment in new projects than they can simultaneously afford. Like choices made around which projects should be chosen to produce, transport, or distribute natural gas, prioritization for emissions reduction projects tend to occur against a global slate of opportunities. Therefore, investments in U.S.-based projects to reduce GHG emissions need to compete favorably against opportunities in other countries. The United States is in a competition for GHG emissions reduction capital investment and should position its policies with that in mind. Thus, it would likely not be a meaningful exercise to simply add up the potential emissions reductions for voluntary Scope 1, 2, and 3 commitments made by companies with a presence in the U.S. natural gas supply chain and necessarily assume that those reductions will definitively occur in the United States.

It is important for policymakers to recognize the degree of certainty around short-term pledges versus longer-term aspirations. Specific company actions over shorter timeframes, ranging from the next few years to the end of the decade, typically have more well-defined actions than net zero GHG pledges for several decades in the future. There is also more expectation that available technologies will evolve over these decades and provide optionality for net zero GHG pathways in the future compared to today. Other solutions (direct

air capture, hydrogen, CCS, etc.) will likely be key pieces of future net zero GHG operations and company strategies, though the scaling of these technologies has only just begun.

b. Methane and Flaring Goals

Additionally, companies in the United States have coalesced around several voluntary sector-wide initiatives that have helped to standardize specific corporate climate commitments around methane emissions and flaring. These initiatives vary in form from commitments to end certain practices to more quantitative reduction targets.

OGCI membership includes 12 of the largest global oil and gas companies. The group has set a framework toward achieving net zero GHG emissions in operations with a collective upstream methane intensity target of well below 0.2% by 2025 and a CI target of 17 kg CO_2e/Boe by 2025 that covers operated upstream oil and gas assets.[126] Ahead of COP27, OGCI announced their Aiming for Zero Initiative[127] whereby signatory companies must strive to reach near-zero methane emissions by 2030. The inventory metrics and details of achieving this goal are not prescribed.

Launched through the World Bank, the Zero Routine Flaring Initiative pledges governments and oil companies to end routing flaring no later than 2030 for operated assets. Entities commit to annually reporting their flaring activities and their respective progress toward the 2030 goal. As part of its Global Gas Flaring Reduction program, the World Bank also publishes an annual report on the state of global flaring. In its 2022 report,[128] the World Bank notes that global gas flaring volumes have remained static over the last decade. While the United States remains one of the top 10 global countries on a flare volume basis (largely due to being among the largest global producers of both oil and gas), the report notes that United States is better than the global average on a production-weighted basis and is the only large producer that has both increased production and decreased aggregate flaring volumes in the last decade. Of note, the three tight oil production basins (Bakken, Permian, and Eagle Ford) where ~89% of U.S. total flaring volumes were attributed saw a ~51% reduction in flaring volumes between 2019 and 2021 that was enabled by increased pipeline infrastructure and processing capacity in those fields.

The Oil and Gas Decarbonization Charter that was announced in 2023 at COP28 in Dubai expanded on the types of companies—including national oil companies—that have committed to similar methane and flaring reduction efforts, including near-zero methane intensity and zero routine flaring by 2030.

The One Future group, comprising more than 50 U.S. companies across the natural gas supply chain and which represents more than 20% of the U.S. natural gas supply chain, has committed to a methane emissions intensity target of 1% or less.[129] The group breaks down the target across the production, gathering and boosting, processing, transmission and storage, and distribution segments. One Future bases their emissions estimates on their own emissions inventory methods, building largely off the GHGRP reporting categories along with some additional sources.

c. Pledge Standardization Organizations

Concerns around the comparability of individual company targets and compatibility of such targets with the Paris Agreement have led to the development of several third-party organizations that seek to standardize corporate disclosures, including the Taskforce on Climate-Related Financial Disclosures and the Global Reporting Initiative, largely to help investors understand the resilience of businesses to future policy considerations for GHG emissions.

Other initiatives, like the Science-Based Targets Initiative (SBTI), have attempted to standardize corporate pledges and assess their compatibility with the Paris Agreement. Notably, SBTI does

126 OGCI. "2023 Progress Report." 2023. https://www.ogci.com/our-progress/ogci-progress-reports.

127 OGCI. Aiming for Zero Methane Emissions Initiative. n.d. https://aimingforzero.ogci.com/.

128 The World Bank. 2022. "2022 Global Gas Flaring Tracker Report." https://thedocs.worldbank.org/en/doc/1692f2ba2bd6408db82db9eb3894a789-0400072022/original/2022-Global-Gas-Flaring-Tracker-Report.pdf.

129 One Future. 2022. "2022 Annual Report on Calendar Year 2021 Methane Intensities." https://onefuture.us/2022-methane-emissions-intensity-report/.

not have a pathway[130] for companies with any level of direct involvement in any part of a supply chain for fossil fuels, including coal, oil, and natural gas, although there have been indications for a desire to restart stakeholder engagements to develop one. Beyond the inability for the oil and gas industry to set science-based targets under SBTI, other concerns include the narrow net zero GHG pathway within the program that is heavily weighted toward renewable energy and explicitly excludes a role for offsets (e.g., nature-based solutions), negative emissions technologies (e.g., direct air capture), or decarbonized fossil fuel supply chains (e.g., CCS).

U.S. government policies, such as financial disclosure or government contracting requirements, should carefully consider the feasibility of deployment within targeted sectors and implications to other national priorities, like energy security and affordability, as part of that decision-making criteria.

FINDING 31: Many companies across the natural gas supply chain are taking voluntary action to reduce their GHG emissions intensity.

FINDING 32: As part of cooperative information sharing efforts, these early actions can be important catalysts for broader industry adoption and discussions.

FINDING 33: Generally, shorter-term pledges have more-defined pathways for achievement, while longer-term, net zero GHG aspirations will need continued policy and technology development.

RECOMMENDATION 12: *The NPC recommends that policymakers encourage early action on GHG reduction and support all technology options to reduce GHG emissions, including low carbon intensity hydrogen, carbon capture and storage, or negative emissions technologies, which may prove important elements of societal net zero GHG emissions goals for the United States.*

130 "Oil and Gas." n.d. Science Based Targets. https://sciencebasedtargets.org/sectors/oil-and-gas.

D. International Efforts

Concurrent to voluntary and regulatory efforts in the United States, international entities have also developed programs aimed at reporting or reducing emissions from the natural gas supply chain. This section does not provide an overview of every international regulation or program but hits on key initiatives, particularly with U.S. trading partners or allies, where there may be possibilities to include elements within U.S. policy or that may influence U.S. exports.

1. Net Zero Producers Forum

In 2021 and 2022, the DOE began a partnership with energy ministries in Canada, Norway, Saudi Arabia, United Arab Emirates, and Qatar on a Net Zero Producers Forum to develop pragmatic strategies for net zero emissions from countries representing ~45% of global oil and gas production. The countries will cooperate on issues like methane abatement, deployment of lower-emissions-intensity energy, CCS, and diversification of revenue from reliance on hydrocarbons. Collaborations between countries will be key to finding the best solutions to reduce GHG emissions globally and the inclusion of major oil- and gas-producing countries in such discussions is vital. At COP28 in 2023, the Net Zero Producers Forum indicated that it would publish case studies of emissions reduction practices to help with broader global uptake.

2. European Union

a. Methane Rules

Following the issuance of the EU methane strategy,[131] the EU Commission released a set of legislative proposals to reduce GHG emissions associated with the EU energy and natural gas market. In late 2023, an agreement was reached

131 European Commission. "Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions on an EU Strategy to Reduce Methane Emissions." October 14, 2020. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52020DC0663.

on legislative text that included methane reduction and reporting requirements for domestic and imported crude oil, gas, and coal. Features of this rule package will continue to be defined, particularly with regards to imports, over the next several years.

The 2023 methane rules in the EU mark the first time that methane is regulated from oil and gas activities across all member countries. The rules include multiple minimum requirements and standards for EU producers, which cover similar source categories, not necessarily with the exact requirements, as U.S. federal and state methane regulations. There have been policy discussions within the EU about the extent of data reporting requirements and/or performance standards for fossil fuel imports. Of note for LNG exports in the United States, though details are being finalized, methane policy discussions in the EU have discussed elements such as:

- MRV at the source level that describes the type of methane information estimation methods, using reporting frameworks such as OGMP2.0 and UNFCCC best practices
- Venting and flaring equipment performance standards and limitations
- LDAR requirements based on OGI and Method 21
- Multiple data reporting requirements, including for imports of oil and gas. The rules highlight the potential to develop intensity standards for imported crude oil and natural gas.
- Verification by EU accredited auditors to demonstrate compliance

There are a few options around how import standards into the EU could evolve. The regulation allows the EU Commission to acknowledge equivalency and facilitate easier importing obligations from those locations (equivalency would be, for example, equivalent of Oil and Gas Methane Partnership (OGMP) 2.0 Level 5 or reporting regulations such as the EPA's GHGRP). Given that the EU and U.S. standards have been developed independently and over similar periods, it is not clear how future U.S. requirements will ultimately compare or how the EU would assess standards that take a different form but achieve similar performance outcomes. There are currently bilateral discussions between the U.S. and EU on harmonization of methane policy.

FINDING 34: There are non-U.S. market programs, like LNG import and monitoring, reporting, and verification requirements, which may also have an influence on emissions performance needs within the U.S. natural gas industry.

FINDING 35: Efforts to accept performance criteria across geographies would be valuable to ensure a level playing field between different suppliers.

b. Carbon Border Adjustment Mechanisms

The main GHG emissions reduction program in the EU is its Emissions Trading System (EU ETS). This covers 40% of the EU's emissions (carbon dioxide from the energy sector, industrial installations, and aviation, with expansion to maritime transport and other sectors in the future) with a goal of 62% reductions by 2030. Achieving this goal is expected to require lowering of the overall emissions cap in the program and reducing free allocations to European industries. The EU expects a resulting increase in "paid" allocations, which will be auctioned off by the EU ETS. Revenues from paid allocations will support climate action and just-transition projects, directed through several government funds.

Phasing out allocations is tightly coupled with introduction of the Carbon Border Adjustment Mechanism (CBAM)—importers of certain goods into the EU will have to pay for emissions of their products at the rate that European industries would lose their free allowances. The intention of CBAM is to create a level playing field with EU and non-EU industries for products, each paying a similar carbon price on their emissions. CBAM is currently focused on emissions-intensive sectors such as iron, steel, cement, fertilizers, aluminum, hydrogen, and electricity—and does not yet include oil and natural gas directly due to a lack of European regulation on these sources and difficulties with supply chain carbon accounting programs. While the first round of industries

included in the CBAM did not directly include oil and natural gas, there are potentially indirect impacts with some customers, like fertilizer plants that export into Europe, needing additional assurance on emissions within their supply chains leading up to the 2026 start of the program. Additional industries may be considered for inclusion in 2030.

To be excluded from CBAMs, importing countries may be linked to the EU ETS system, such as Norway, Switzerland, Iceland, Lichtenstein, or demonstrate their own equivalent carbon pricing to the EU ETS. For the United States, it is unclear how, or whether, equivalency would be established with the EU ETS due to the lack of a national price on carbon emissions. However, the passage of the Inflation Reduction Act, with an incentive-based structure for reducing emissions, may allow for discussions on equivalency. Even without equivalent national policy, if the producer has already paid a price for the carbon in a third country, the corresponding cost can be deducted for the EU importer.

There are potential equity concerns around CBAM mechanisms where trade impacts may be focused on emerging markets that have a high energy intensity of production, no carbon markets, and a lesser ability to track national emissions than more economically developed nations.

3. Japan

For most of the past 50 years, Japan has been the world's largest importer of LNG. The nation is an economic and industrial powerhouse and is the world's third-largest economy in terms of GDP. With limited domestic natural resources, Japan imports nearly all of its energy. LNG is, and will likely continue to be, essential to Japan's economic growth, energy security, and decarbonization priorities for the foreseeable future. Japan's industrial base and the need for imported energy will continue to feed Japan's strong geostrategic relationships with the U.S. and like-minded allies in the region. Japan's energy security translates directly to its key role as a geopolitical linchpin in the Indo-Pacific.

In 2021, Japan's Ministry of Economy, Trade, and Industry (METI) announced "The 6th Strategic Energy Plan" to achieve carbon neutrality by 2050 and reduce GHG emissions by 46% in FY 2030 from FY 2013 levels. The previous decade's shift away from zero direct GHG emissions nuclear power will make achieving ambitious GHG reduction goals more challenging. Before the Fukushima disaster in 2011, nuclear power accounted for nearly 30% of Japan's electricity generation, and according to the EIA, declined to 3% in 2021. Although the intention is to increase nuclear power generation to 22% by 2030, the rapid return of reactors is not a forgone conclusion due to sociopolitico and regulatory risks.

The geopolitical fallout from Russias 2022 invasion of Ukraine renewed international attention on the importance of affordable, diversified, reliable, and accessible energy supplies. It also starkly reemphasized the benefits of geopolitically advantaged supply and the perils of concentration risk. Japan was impacted by market tightening conditions following the invasion, as the EU largely transitioned away from Russian pipeline gas imports by replacing many of those volumes with LNG, which is discussed in more detail in Section III of this chapter.

Even as Japan introduces, and reintroduces, more renewable and nuclear power into its energy mix, the EIA reports that at 72%, fossil fuels account for the largest portion of Japan's electricity generating capacity—natural gas is the largest source (28%), with solar (22%), coal (18%), and crude oil (11%) trailing. Moreover, at 10.3 Tcf/yr, approximately three times the amount of LNG imports of 3.3 Tcf/yr in 2022, Japan has the world's largest regassification capacity that will be utilized in preparation against potential future market volatility and supply disruptions.

Yasutoshi Nishimura, Minister of METI, announced that Japan will launch a new LNG reserve system starting in 2023. Like Japan's Strategic Petroleum Reserve, the new policy intends to secure natural gas resources to safeguard against the type of unanticipated market conditions experienced in the summer of 2022, when Russia's invasion of Ukraine increased LNG prices in Asia and Europe to reach a record $70 per million British thermal units (MMBtu),

equivalent to more than $400 per barrel of crude oil. Such price shocks were partly responsible for a global rise in inflation that continue to require global fiscal and monetary interventions to ameliorate adverse economic impacts on households and industries unprepared to shoulder the burden of skyrocketing energy costs, as was the case in Japan.

Going forward, Japan's leaders appear committed to better insulating the country from the kind of deep geopolitical disruptions that have far-reaching, and unintentional, consequences. The EIA reports that in 2022, Japan imported the majority (68%) of its LNG from the Asia-Pacific region: Australia (42%), Malaysia (17%), Brunei (5%), and Indonesia (4%).

Although the United States only accounted for a small percentage (6%) of Japan's total LNG imports in 2022, U.S. LNG is strategically relevant to Japan and may grow in importance. In macro terms, increasing the global supply of LNG will have multiple benefits, especially for countries heavily dependent on imports. LNG export infrastructure on the Pacific coast of North America would have shorter shipping distances to Japan than U.S. Gulf Coast facilities and would not transit the Panama Canal.

That is why, in addition to increasing U.S. LNG exports across geopolitically aligned global markets, the Japanese government is also a proponent of increased global investments in LNG infrastructure and upstream natural gas projects.[132] Absent greater investments in critical infrastructure, and advancing public-private partnerships, the global LNG market will likely face additional challenges in terms of price stability and accessibility. Other nations that continue to depend on LNG imports would be well served to follow Japan's lead in supporting the LNG sector. Public-sector commitment sends an important message to the private sector, and especially the financial services sector, which will spur capital investments to help reduce the overall CI of the electricity mix, particularly when paired with plans for CCS, and meet current and future thresholds for energy security and affordability.

E. Global Efforts, Including the United Nations

1. Global Emissions Trading Systems

In 2021, there were 30 operating ETS systems across different nations, regions, and subnations, that covered more than 8 Gt CO_2e, or 16.4% of global emissions.[133] Emissions trading systems and carbon pricing systems offer a potential policy mechanism to reduce GHG emissions from the natural gas supply chain and other sectors of the economy. At a high level, programs that price GHG emissions would incentivize the most cost-effective reductions at the societal level, regardless of sector. Existing trading programs like the EU ETS, the U.K. ETS, and the California Cap-and-Trade system include carbon dioxide emissions from aspects of the natural gas supply chain within the geographic bounds of the program. Due to the difficulty with measuring emissions, particularly from fugitive sources, these programs have generally not included methane emissions from the oil and gas or other sectors, but work is underway to develop the MRV programs for future inclusion. Current voluntary efforts that are focused on the development of measurement-based reporting frameworks may begin to provide the necessary level of assurance that would be needed for inclusion of methane emissions sources from the oil and gas and other sectors within ETS programs.

2. International Methane Emissions Observatory (IMEO)

The IMEO is a UNEP program, enacted in 2021 and funded by the European Commission, with the goal of standing up scientific studies for filling knowledge gaps on global methane emissions, maintaining a repository of public global emissions data, and supporting various subinitiatives such as the OGMP2.0 reporting program discussed in detail in this chapter. In terms of scientific studies, there remains a global knowledge gap, as much of the methane research in the last decade has focused on measurements within the United

132 Obayashi, Yuka and Katya Golubkova. "Japan's JOGMEC gearing up to support new LNG projects." Reuters. January 25, 2024. https://www.reuters.com/business/energy/japans-jogmec-gearing-up-support-new-lng-projects-2024-01-26.

133 The World Bank. 2021. "State and Trends of Carbon Pricing 2021." Washington, D.C. http://hdl.handle.net/10986/35620.

States and Canada, where there has been funding available from governments and private industry and a general permissive regulatory environment for conducting research (i.e., governments do not ban third-party measurements from planes or drones that are conducted in a safe manner). Prior to the formation of the IMEO, the UN led these scientific studies under the CCAC mechanism and with financial support from counties and industry (via OGCI), but industry funding of research is not accepted by IMEO. Published scientific studies to date include measurements in Mexico, coal-seam gas in Australia, and a multimodal study in Romania. The IMEO seeks to conduct future work in Angola, Azerbaijan, Colombia, Gabon, Oman, Poland, and from the LNG sector.

One of the future functions of the IMEO is to act as a methane data repository for different sources, including OGMP2.0 reporting, measurements from scientific studies, public (and potentially private) remote sensing data, and national inventories. IMEO's stated goal is to inform companies and governments of strategic mitigation opportunities. The IMEO is only a few years into existence, so the ultimate success and level of data availability within this model is not known. While such a function may offer value to many countries around the world at different stages of their methane journey, U.S. policy considerations in relationship to the IMEO may be more complex, particularly given detailed emissions data already available through EPA, specific criteria at EPA for data inclusion in the GHGI, and the timing of information provided to the United Nations versus U.S. regulatory programming. Several IMEO staff also hold positions with EDF.

In 2022, IMEO announced the Methane Alert and Response System (MARS) as another sub-initiative aimed at identifying and informing global operators about very large point source methane emissions. MARS receives financial support from the European Commission, U.S. government, Global Methane Hub, and the Bezos Earth Fund. The MARS program will coordinate emissions detections from various global scanning and mapping satellites, such as the European Space Agency (ESA) TROPOMI (method detection limit >10,000 kg/hr) and ESA Sentinel-2 (~2,000 kg/hr-5,000 kg/hr). Coordinated satellites with differing capabilities of detecting area emissions and attributable point sources work together through an interactive method called "tip and cue." By comparison, the EPA has finalized a super-emitter program at 100 kg/hr as part of its NSPS OOOOb and OOOOc rules.

While the MARS program may, in the future, yield valuable insights around the location of the largest methane emissions globally and information to reduce emissions from certain sources, the program is not fully implemented today, particularly around the provision of measurement-informed methane emissions inventories. Some stakeholders within the oil and gas industry have noted concerns with one or more elements in the IMEO approach. First, current public satellites being used by IMEO may not precisely identify the exact location of a methane plume within a dense oil and gas production area. Production areas like the Permian Basin may have multiple operators within a small geography that may not be resolvable with the current generation of technologies. This may lead to potential misidentification of the operator responsible or situations where an operator is meant to prove that an emissions event did not occur, potentially in a very public forum. Second, free screening by IMEO at high detection limits may act as a disincentive to global deployment of technologies with better detection limits that likely capture a better cross section of emissions from the sector. For example, aircraft that are commonly used in the United States have detection limits well below 10 kg/hr. Third, the initial focus on satellite technologies does lead to an equity concern in that satellite technologies are well suited to low cloud cover and onshore assets, which may lead to a disproportionate focus on certain countries or situations for which satellites are more ideally suited. This may introduce some bias into perceptions of the methane emissions performance of some countries or operators, that may not be indicative of true relative performance.[134] Specifically, IMEO plans to publish a country-specific methane intensity supply index for use in Europe that raises concerns from some stakeholders around data accuracy and policy

134 Gao, M., Xing, Z., Vollrath, C., Hugenholtz, C.H., and Barchyn, T.E. "Global Observational Coverage of Onshore Oil and Gas Methane Sources with TROPOMI." *Scientific Reports.* 13 (16759). October 5, 2023. https://doi.org/10.1038/s41598-023-41914-8.

signals, particularly if such approaches are based on satellite information. While the final form of the metric has not been announced, the use of country-average or basin-average numbers may send problematic signals for continued emissions reductions due to free-rider concerns for high emitters and the inability to differentiate performance for leading performers.

In the context of international policy discussions around methane emissions, it should be noted that the United States is in a unique starting position globally. As discussed in other sections, larger operators have been reporting source-specific GHG emissions publicly as part of the GHGRP for a number of years. Programs like the DOE ARPA-E MONITOR program have led to the development of many advanced methane detection and measurement technologies that have been deployed by operators. Scientists have conducted numerous measurement studies across different regions and types of oil and gas operations. Operators have been complying with state and federal emissions regulations in the oil and gas sector. These are the types of programs and outcomes that international organizations are trying to start and implement in other jurisdictions. U.S. stakeholders should play an important role in sharing best practices and experiences globally as other regions are beginning their methane management journeys, and the U.S. experience on methane management should be a key part of global discussions on methane management, reporting, and harmonization.

FINDING 36: The International Methane Emissions Observatory is forming an international methane data repository, offering research funding for methane emissions in new geographies, and launching a global satellite monitoring program.

FINDING 37: U.S. policymakers should recognize the current existence of a world-class methane data collection program (the Greenhouse Gas Reporting Program) with more-granular public data available and globally leading understanding of advanced methane technology in the United States.

RECOMMENDATION 13: *The NPC recommends that DOE and EPA proactively share best practices on Greenhouse Gas Reporting Program (GHGRP) data collection in global forums and promote acceptance of GHGRP data as part of international GHG emissions reporting initiatives while acknowledging the need for continuous improvement of data collection.*

3. International Shipping

Under the UNFCCC, GHG emissions reductions associated with international transportation via shipping and airplanes are overseen by international organizations versus individual country GHG emissions inventories and reduction commitments. Policies from the IMO may have influence on the operation of ships powered by LNG, such as those used in the natural gas supply chain to deliver LNG cargoes, and on the overall demand for natural gas as a fuel in the shipping sector.

The IMO was developed as a cooperative mechanism for global governments to promote safety at sea, given the transnational nature of the shipping industry. In 2011, the IMO began to study ways to reduce GHG emissions from the shipping industry and in 2018 led to the establishment of global goals to reduce annual GHG emissions by 40% in 2030, 70% by 2050, and to be emissions free by end of century. A major study and the resulting recommended strategy for voluntary adoption launched at COP27 with several member states joining as part of the Marine Environment Protection Committee resolution.[135] The strategy outlines goals that address all types of carbon reductions—such as improved efficiency, zero-carbon fuel replacements, data collection, and implementation of an Energy Efficiency Design Index.

The final report of the Fourth IMO Greenhouse Gas Study[136] includes GHG emissions estimates

135 IMO. 2023. "IMO's Work to Cut GHG Emissions from Ships." https://www.imo.org/en/MediaCentre/HotTopics/Pages/Cutting-GHG-emissions.aspx.

136 IMO. 2021. "Fourth IMO Greenhouse Gas Study 2020." https://wwwcdn.imo.org/localresources/en/OurWork/Environment/Documents/Fourth%20IMO%20GHG%20Study%202020%20-%20Full%20report%20and%20annexes.pdf.

from different maritime fuel options and engine types. The report suggests updates to the IMO emissions reduction strategy such as immediate recognition and inclusion of all GHGs (including methane) in the CO_2 index so that life cycle assessments based on fuel choice can accurately account for LNG methane emissions, requirement of low-methane-slip engines or methanol fuels, research and development activities to explore engine retrofits and methane oxidation catalysts, and new emissions factors for LNG engines that include a speed-power correction factor, vessel age, and yearly operational profile.

F. Orphan Wells

1. Background and Definitions

When classifying different types of producing and nonproducing wells, common definitions and terminology are important for an understanding of the types of wells that are being discussed. Modern regulations across the United States generally require that operators plug and abandon wells at the end of their useful life. The plugging process typically requires a workover rig and involves the placement of cement and additives at defined intervals in and outside the wellbore to prevent fluid flow to the surface or other underground formations.

The Interstate Oil and Gas Compact Commission (IOGCC)[137] published the following definitions for commonly used terms for wells that have not previously been plugged:

- *Idle wells*: wells that are not producing, injecting, or otherwise being used for their intended purpose. Idle wells have the potential to be used in the future for production or associated activities.
- *Orphan wells:* a subset of idle wells for which the operator is unknown or insolvent

Generally, regulation of abandonment practices and financial assurance requirements for closure, also known as bonding, occur at the state level, except for federal and Tribal lands. The IOGCC notes that oil and gas drilling activities began in the mid-1800s and that regulatory requirements for the industry began to emerge in the early to mid-1900s, and there may be limited details about plugging status or the existence of wells from locations developed and abandoned before these recordkeeping requirements were developed. Thus, IOGCC further defines documented and undocumented wells, which are distinct from the idle versus orphan status discussion above.

- *Documented well:* a well for which the regulatory agency has a drilling report, completion report, inspection report, or other record establishing the existence of the well
- *Undocumented well:* a well that is unknown to the regulatory agency, or which requires further records research or field investigation for verification

Undocumented wells can be undiscovered for years, generally until nearby land development occurs. It is important to note that not all undocumented wells would be a source of appreciable GHG emissions, and undocumented wells may be challenging to detect in the field, particularly if they aren't emitting methane or other substances or have no metallic elements at or near the surface. State agencies typically have mechanisms for receiving information about the location of undocumented wells.

Based on the 32 states participating in IOGCC work on idle and orphan wells, ~92,198 documented orphan wells existed nationally in 2021, which was an increase of more than 50% since 2018. The IOGCC notes that this increase is primarily due to state efforts to improve their inventories of orphan wells, confirming responsible party records with other databases, and conducting field verifications of potential wells. State regulators typically have a continuous process to update counts after completion of the documentation process. Other organizations[138] have produced their own estimates for national orphan well counts, where the definitions may differ from official counts in state programs. Any estimate

137 IOGCC. 2021. "Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies 2021." https://iogcc.ok.gov/sites/g/files/gmc836/f/iogcc_idle_and_orphan_wells_2021_final_web.pdf.

138 Boutot, J., Peltz, A.S., McVay, R., and Kang, M. 2022. "Documented Orphaned Oil and Gas Wells across the United States." *Environmental Science & Technology*. 56 (20): 14228–36. https://doi.org/10.1021/acs.est.2c03268.

Region	Plugged Wells		Unplugged Wells	
	Emissions Factor (g/hr/well)	Number of Wells Measured in Underlying Study	Emissions Factor (g/hr/well)	Number of Wells Measured in Underlying Study
Appalachia	0.36	29	30.57	42
Rest of United States	0.002	119	10.02	19

Source: EPA, 2018, "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016: Abandoned Oil and Gas Wells."

Table 1-6. *EPA GHGI Methane Emissions Factors for Plugged and Unplugged Wells*

for undocumented orphan wells would by nature be imprecise due to the lack of information within the state agencies, but IOGCC estimates a national count in the 300,000–800,000 range. It is important to note that not all undocumented wells would be a source of GHG emissions.

2. National GHG Emissions Estimates

Consistent with GHGI-development guidance documents from the IPCC, the GHGI provides an annual estimate of emissions associated with abandoned oil and gas wells. Abandoned wells is a broader term than orphan wells and includes previously plugged wells and certain idle wells with a responsible operator. For 2021, the EPA estimate[139] for the source category is 8.2 MMT CO_2e from methane emissions, which represents ~1.1% of national methane emissions and ~0.1% of national GHG emissions with a 95% uncertainty range from 1.4 MMT CO_2e to 25.1 MMT CO_2e.

For developing national GHG emissions estimates for abandoned wells, EPA uses separate emissions factors and well-count estimates for plugged and unplugged wells. Within its definition of abandoned wells for the GHGI, EPA includes wells that would not be considered abandoned by states or operators, and there is no consistency across-the-board with definitions of abandoned wells, compared to terminologies like plugged or idle wells. For the current national inventory estimate, EPA uses an estimate of 3.7 million total wells abandoned since the beginning of oil and gas drilling in the United States, which includes estimates for undocumented wells and estimates that 2.2 million wells were unplugged as of 2021. Based on two peer-reviewed field studies, EPA developed methane emissions factors for plugged and unplugged wells for operations in Appalachia and other U.S. production regions that are outlined in the Table 1-6.

The methane emissions factors for plugged wells (<1 g/hr) and unplugged wells (10 g/hr-30 g/hr) are several orders of magnitude less than expected emissions from operating facilities. For example, in 2023 the EPA included alternative technology thresholds[140] of 1 kg/hr-15 kg/hr methane in its periodic screening equivalency matrix.

3. Federal Policies

The Infrastructure Investment and Jobs Act (IIJA) included $4.7 billion in potential funding through 2030 to be allocated to federal agencies, states, and Tribes to support efforts to plug orphan wells on federal, state, Tribal, and private lands and to identify and research currently undocumented wells.[141] Funding for this program is coordinated through the DOI. In 2022, an initial grant of up to $25 million was given to 22 states to supplement ongoing state efforts to plug documented orphan wells and two states received $5 million grants to support methane measurement

139 EPA. 2023. "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2021." Table 2-8. https://www.epa.gov/system/files/documents/2023-04/US-GHG-Inventory-2023-Main-Text.pdf.

140 EPA. "40 CFR Part 98 Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems." *Federal Register* Vol. 88, no. 146, August 1, 2023: 50282: https://www.govinfo.gov/content/pkg/FR-2023-08-01/pdf/2023-14338.pdf.

141 U.S. Department of the Interior. "Through President Biden's Bipartisan Infrastructure Law, 24 States Set to Begin Plugging over 10,000 Orphaned Wells." August 25, 2022. https://www.doi.gov/pressreleases/through-president-bidens-bipartisan-infrastructure-law-24-states-set-begin-plugging.

and orphan well documentation programs. State-level estimates of the number of wells that could be plugged with the initial grants varies based on the well depth, remoteness of sites, and existing state-level contracts with workover rig crews but ranged from 12–18 wells in Alaska to more than 1,000 wells each in Kentucky, Kansas, and Oklahoma. The existence of multiple programs among states, Tribes, and federal agencies offers a potential opportunity for best practice sharing, particularly around improving the cost of plugging activities by these actors. As of October 2023, states had plugged ~6,000 wells with initial grant funding. Additional tranches of grant funding to states are expected between 2024 and 2030.

While grants authorized under the IIJA have increased available resources for state-level orphan well plugging programs, the DOI grants have stipulations that have added complexity and cost. For example, the IIJA includes a requirement to measure emissions to understand the emissions mitigation associated with the allocated funding, which has been estimated at $4,000 per site. Several states have noted the inherent trade-offs between using resources for upfront emissions measurement and the number of wells that can be plugged with a given budget.

With funding from the IIJA, DOE has a supporting role for states and other federal agencies. This includes $30 million in research funding to help with the development of tools to find and characterize locations and methane emissions for currently undocumented orphan wells, including providing expert support from multiple federal labs. In particular, there is a focus on developing technologies that could reduce the cost of methane measurements in this application. The U.S. Geological Survey is currently conducting additional research into expanding sample sizes for measurements of plugged and unplugged wells and researching subsurface factors that may contribute to the presence or absence of surface-level methane emissions from orphan wells. The technology needed to rapidly characterize methane emissions from abandoned wells could use further development, particularly around quantification of emissions in the gram per hour range or simplified screening tools to estimate emissions with limited on-site data collection needs that would help to better prioritize limited state-level abatement resources.

4. State-Level Policies

While the IIJA increased federal funding for the plugging and abandonment of orphan wells, state-level regulatory programs have traditionally played a leading role in managing this issue. IOGCC has completed work to summarize and compare state-level policies and estimate counts of orphan wells.[142] While there is variation among states, such programs typically include elements around mechanical integrity testing for idle wells, financial assurance requirements for operators to provide money for plugging and site restoration in the event that an operator defaults, and supplemental funding mechanisms for orphan wells, which are generally funded by taxes, fees, or other assessments on the oil and gas sector. Detailed analysis of these state-level regulatory programs and financial assurance mechanisms is a complex topic that is outside the scope of this study.

5. Market-Based Mechanisms

While costs vary among states and well locations, characteristics, and conditions, estimates of the average expenditure for plugging an orphan well and site restoration range from $25,634 between 2018 and 2020[143] from IOGCC to $76,000[144] from Resources for the Future. Assuming these values are relatively accurate in the future and the funding levels in the IIJA remain, this funding could facilitate plugging of approximately half of the current documented orphan well count from IOGCC.

142 IOGCC. 2021. "Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies 2021." https://iogcc.ok.gov/sites/g/files/gmc836/f/iogcc_idle_and_orphan_wells_2021_final_web.pdf.

143 IOGCC. 2021. "Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies 2021." https://iogcc.ok.gov/sites/g/files/gmc836/f/iogcc_idle_and_orphan_wells_2021_final_web.pdf.

144 Raimi, D., Krupnick, A.J., Shah, J.S., and Thompson, A. "Decommissioning Orphaned and Abandoned Oil and Gas Wells: New Estimates and Cost Drivers." *Environmental Science & Technology*. July 14, 2021, 55 (15), 10224-10230. https://doi.org/10.1021/acs.est.1c02234.

Groups like the American Carbon Registry have proposed voluntary carbon market approaches as a potential method to generate additional flow of capital to reducing potential GHG emissions from orphan wells and potentially increase funding beyond current federal and state programs. As with any well intervention activity, plugging orphan wells has potential safety risks, and care should be taken to ensure that crews completing the work are properly trained. Clarifications around residual financial liability for private sector actors that plug an orphan well and improvements to technology that could rapidly identify higher-emitting orphan wells with more credit generation potential could help to spur additional investments in this area. IOGCC has asked the DOI to revise its guidance for future IIJA grants to allow for the issuance of carbon credits associated with orphan wells plugged with grant funds to provide an additional means of financing plugging for additional wells.[145] Consistent with other voluntary carbon market programs, considerations around additionality, verification, and validation would be important elements of such a program.

FINDING 38: Appropriations from Infrastructure Investment and Jobs Act is increasing the amount of funding available for state- and federal-run efforts to plug orphan wells.

FINDING 39: Despite increased funding, challenges remain around measurement, prioritization for plugging efforts, and the total amount of resources available.

RECOMMENDATION 14: *The NPC recommends relevant federal agencies support IOGCC Resolution 23.101, which would allow states to pursue carbon credits for well plugging and restoration activities as a source of supplemental funding for state orphan well programs.*

145 IOGCC. "Resolution 23.101 – Urging the Department of Interior to Allow the Use of Carbon Credits as Program Income for Formula and Performance Grants Under Section 40601 of the Infrastructure Investment and Jobs Act." 2023. https://oklahoma.gov/content/dam/ok/en/iogcc/documents/resolutions/resolution_23.101_with_seal_1.pdf.

III. BROADER POLICY CONSIDERATIONS FOR NATURAL GAS

Good energy policy includes considerations for affordability, security of supply, reliability, and GHG emissions intensity. Policy considerations for natural gas should balance these pillars. This section discusses the broader policy fit for U.S. natural gas as part of the economic and energy security for the country and internationally.

A. Domestic Impacts of the U.S. Natural Gas Supply Chain

DOE data and other studies show that the U.S. natural gas supply chain has provided a sizable benefit for the U.S. economy,[146, 147] though most economic data aggregate the natural gas and oil industries. In terms of GDP, state-level revenue, and jobs created, increased U.S. natural gas production and exports have caused positive impacts for the U.S. economy—supporting millions of jobs and enabling the United States to not only be energy self-sufficient but become, as of the first half of 2023, the largest supplier of LNG in the world.[148] Natural gas production has supported consumers and manufacturing industries with an abundant low-cost supply of energy, increasing U.S. competitiveness in those industries in addition to reducing the energy burden on consumers. On a subnational and local level, assessing the impacts is complicated; natural gas-producing states have benefited economically—some more so than others—but more localized regions may more directly experience the positive and negative trade-offs of the natural gas supply chain and associated infrastructure. A detailed coverage of societal considerations and impacts is included in Chapter 2.

146 DOE. "U.S. Oil and Natural Gas: Providing Energy Security and Supporting Our Quality of Life." September 2020. https://www.energy.gov/sites/prod/files/2020/10/f79/Natural%20Gas%20Benefits%20Report.pdf.

147 NERA. "Updated Macroeconomic Impacts of LNG Exports from the United States." 2014. https://www.nera.com/insights/publications/2014/updated-macroeconomic-impacts-of-lng-exports-from-the-united-sta.html.

148 EIA. "The United States Became the World's Largest LNG Exporter in the First Half of 2022." July 25, 2022. https://www.eia.gov/todayinenergy/detail.php?id=53159.

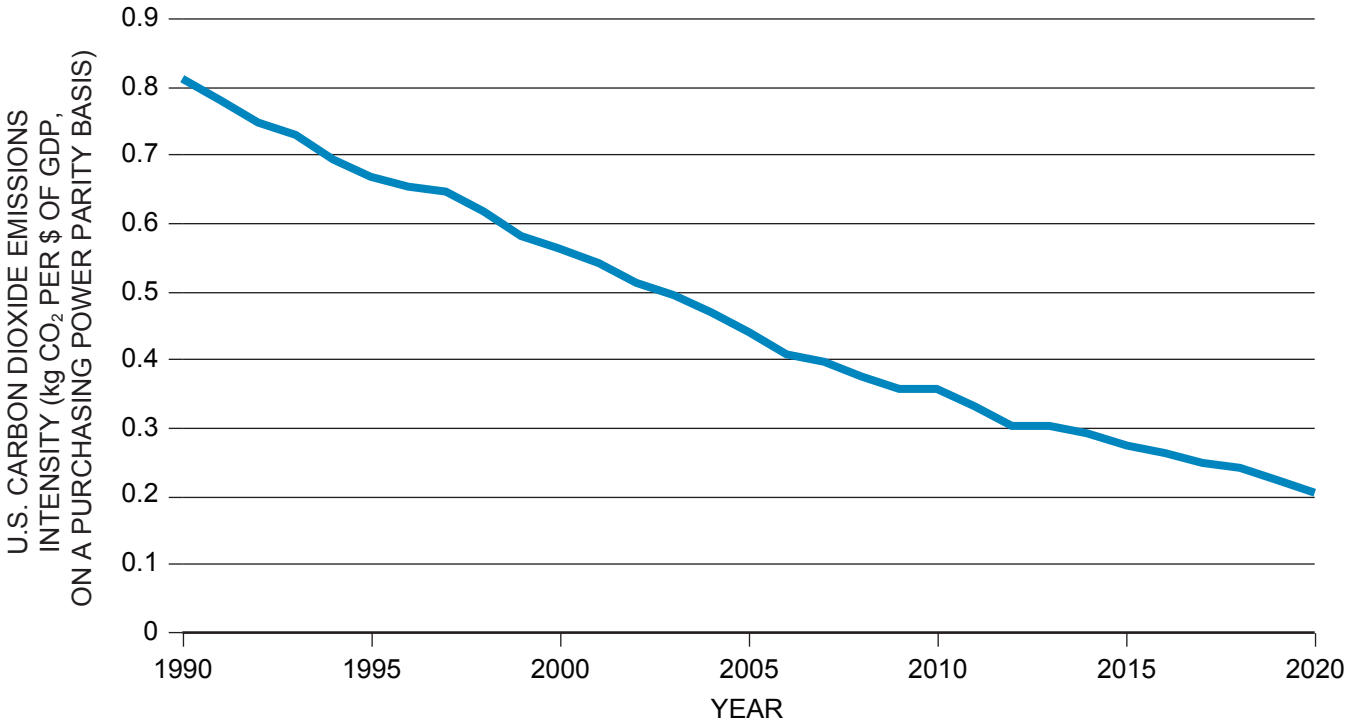
Natural gas production and combustion result in GHG emissions, which translate into implicit costs. However, as recognized by EIA and others, natural gas production and consumption has to some degree replaced production and consumption of other higher-carbon-emitting fuels, most notably coal, which, in the aggregate, has helped the United States reduce its overall carbon emissions per unit of GDP, as shown in Figure 1-31. Natural gas has also played an important balancing role in the power grid as the percentage of intermittent renewable power generation has increased. As the North American Electric Reliability Corporation concluded in 2023, "The natural gas supply and infrastructure is vitally important to electric grid reliability, even as renewable generation satisfies more of our energy needs. Fuel supply and delivery infrastructure must be capable of meeting the ramp rates of natural gas-fired generators as they balance the system when solar generation output declines."[149]

The availability of low-cost natural gas has benefited the U.S. manufacturing industry, particularly chemicals, fertilizer, and petrochemical production, through providing an abundant domestic supply of affordable fuel and feedstock (Figure 1-33).[150] By producing abundant natural gas, the industry has kept natural gas prices for American consumers markedly lower than prices in most other parts of the world as shown in Figure 1-12 and Figure 1-32.

This, in turn, has attracted industrial, chemical, and manufacturing facilities to the United States. Favorable natural gas prices have provided an economic advantage for chemical manufacturing in the United States. During the last decade, 343 chemical manufacturing projects involving $203 billion of investment have been completed, placed under construction, or are in the planning stages. These projects have created or are projected to create 757,000 permanent

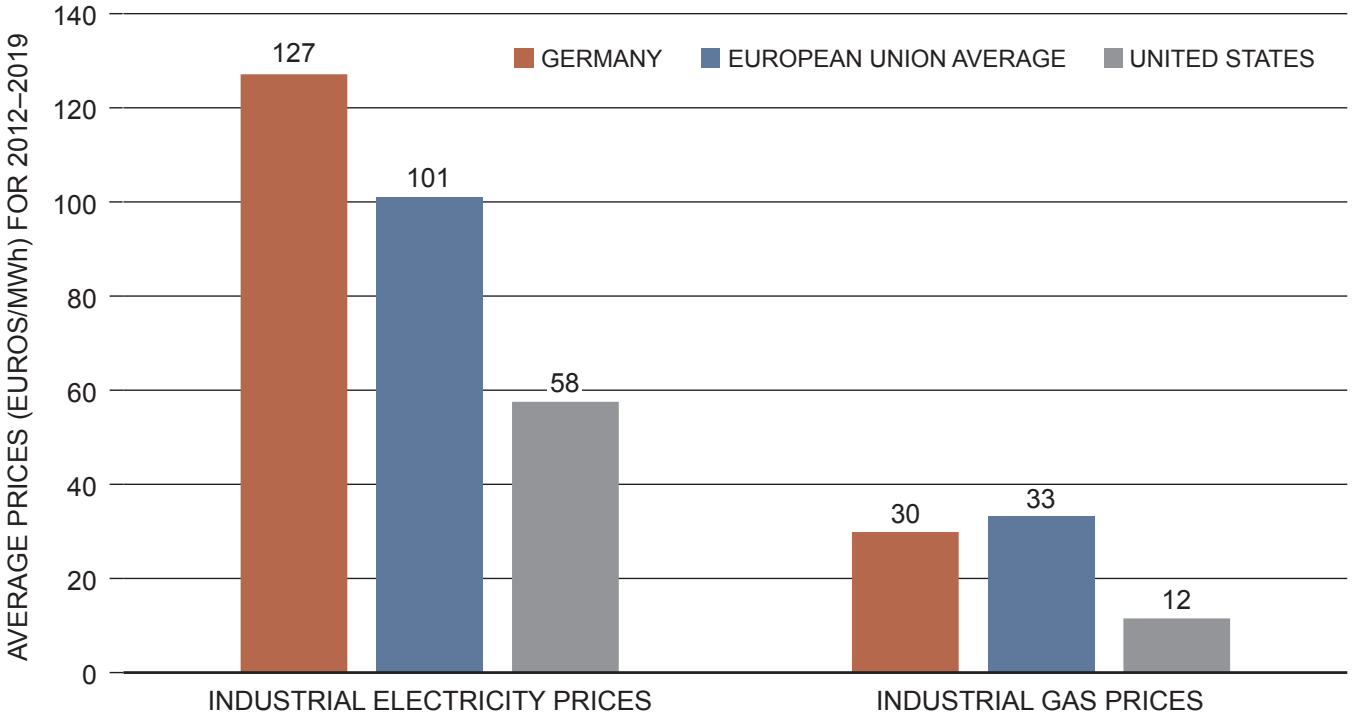
149 North American Electric Reliability Corporation. 2023. "2023 Summer Reliability Assessment." https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf.

150 DOE. "U.S. Oil and Natural Gas: Providing Energy Security and Supporting Our Quality of Life." September 2020. https://www.energy.gov/sites/prod/files/2020/10/f79/Natural%20Gas%20Benefits%20Report.pdf.



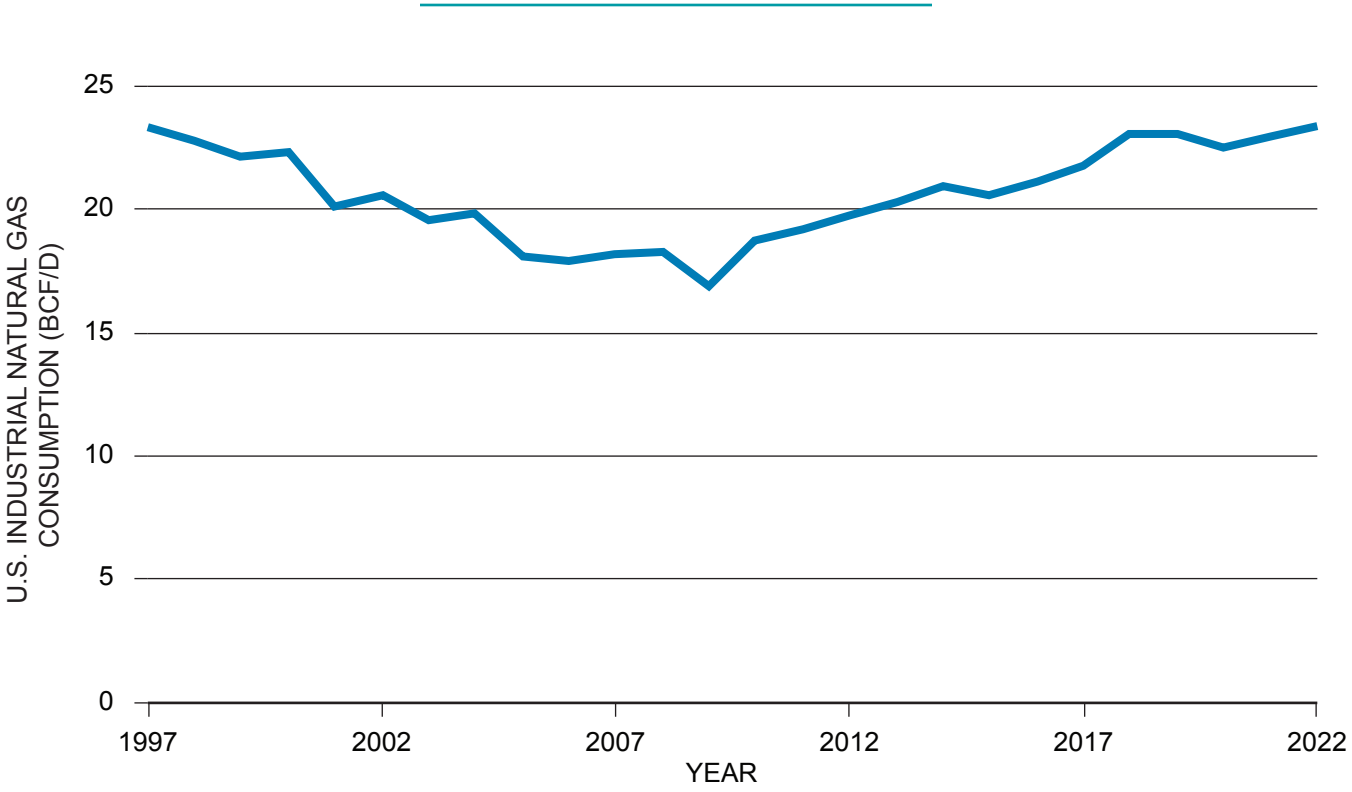
Source: Climate Watch, 2020, "GHG Emissions."

Figure 1-31. *CO_2 Emissions Intensity per Unit of Economic Activity in the United States*



Source: Roland Berger, 2022, https://www.rolandberger.com/publications/publication_pdf/roland_berger_de_industrialization_in_europe.pdf.

Figure 1-32. *Comparison of Energy Costs in the EU, Germany, and United States*



Source: DOE, 2024. "Annual U.S. Industrial Gas Consumption."

Figure 1-33. *U.S. Industrial Gas Demand 1997-2022*

new jobs and an annual economic output of $289 billion by 2025.[151]

Ammonia is the primary source of nitrogen in fertilizer, which is important for global agricultural production and yield. Globally, most ammonia production is based on a steam methane reformation process with natural gas as an input. According to the EIA,[152] ammonia is a globally traded commodity that tends to track global natural gas benchmark prices. However, low-cost natural gas input pricing led to a doubling of U.S. ammonia production between 2012 and 2021 both from the addition of new manufacturing capacity and from restarting facilities that were mothballed in the early 2000s due to high U.S. natural gas prices. While the U.S. remains a net importer of ammonia, the country imported only 14% of supply in 2021, compared to 37% in 2012, with China and Russia being the largest global ammonia producers in 2021.

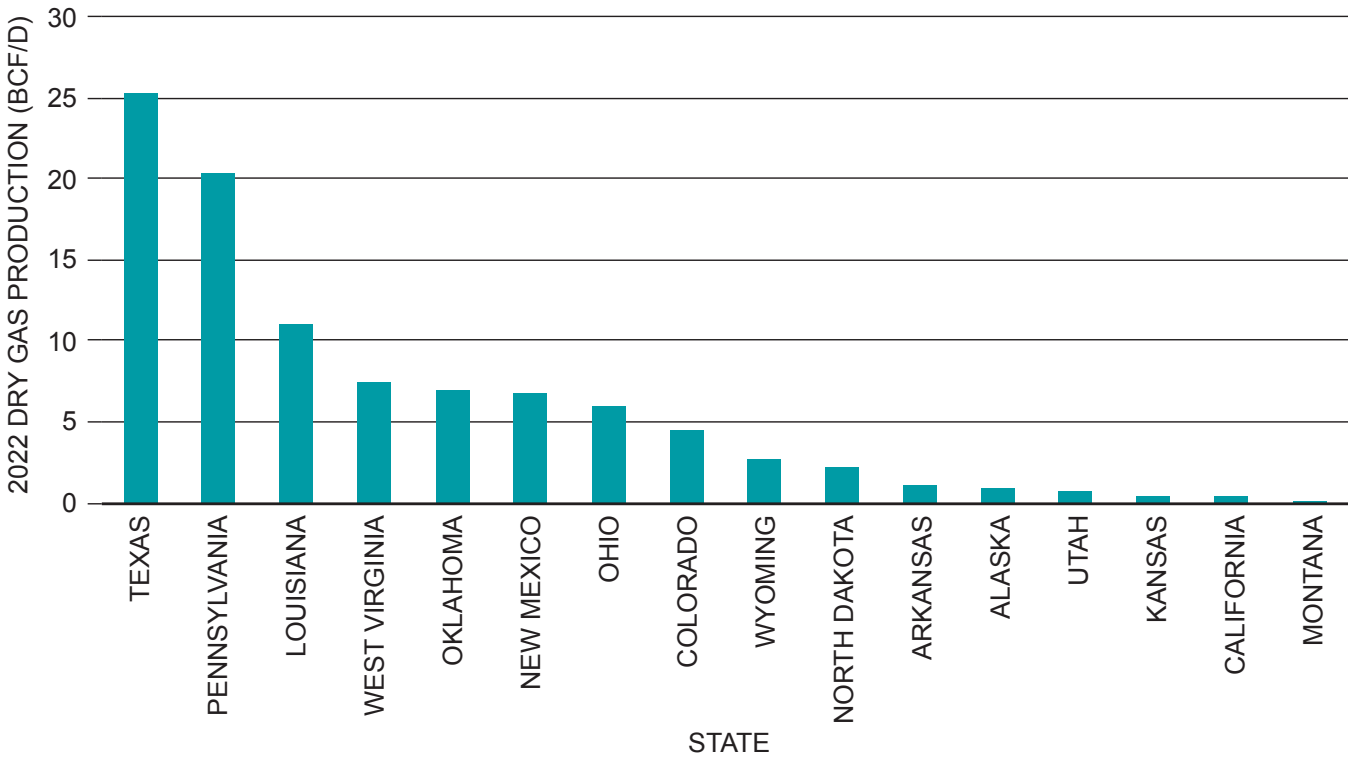
Natural gas fuels supported 211,773 jobs in 2022 while the natural gas electricity industry supported 111,196 workers.[153] When indirect jobs are included, the oil and natural gas extraction industry supports 896,000 jobs,[154] including service, supply jobs, and induced jobs. Wages in the industry tend to be higher, with the natural gas extraction industry having an annual average wage of $112,000, more than double the annual average wage of $51,000 in the private sector.

151 DOE. "U.S. Oil and Natural Gas: Providing Energy Security and Supporting Our Quality of Life." September 2020. https://www.energy.gov/sites/prod/files/2020/10/f79/Natural%20Gas%20Benefits%20Report.pdf.

152 EIA. "U.S. Ammonia Prices Rise in Response to Higher International Natural Gas Prices." May 10, 2022. https://www.eia.gov/todayinenergy/detail.php?id=52358.

153 DOE. "United States Energy & Employment Report 2022." June 2022. https://www.energy.gov/sites/default/files/2022-06/USEER%202022%20National%20Report_0.pdf.

154 DOE. "U.S. Oil and Natural Gas: Providing Energy Security and Supporting Our Quality of Life." September 2020. https://www.energy.gov/sites/prod/files/2020/10/f79/Natural%20Gas%20Benefits%20Report.pdf.



Source: EIA, 2024.

Figure 1-34. *Top Natural Gas Producing States*

1. Economic Impacts in Producing States

States with natural gas production benefit significantly. Nine states provide approximately 87% of onshore natural gas production[155] (Figure 1-34). And just two states—Texas and Pennsylvania—account for 45% of the nation's natural gas production. At the state level, these economic impacts include tax revenue for state budgets and local supply purchases that support indirect jobs and economic benefits.

In 2022, taxes paid by the oil and natural gas industry to the state of Texas reached a total of $10.8 billion or 14% of the state's $77 billion in state tax revenues.[156] In addition, the Texas oil and natural gas industry, in 2019, purchased $220 billion in goods and services, of which 80% came from Texas businesses.[157, 158]

The New Mexico Oil and Gas Association estimates that $1.2 billion of the state's $6.2 billion budget in 2019 came from revenue on federal land, including royalties, bonuses, and other payments.

In North Dakota, oil and natural gas taxes provided $18 billion for fiscal years 2008–2018 for the state, accounting for more than 45% of total tax revenues.

For the federal government, lease sales and royalties that companies pay on oil and gas extracted from federal lands brought in more than $83 billion in revenue over the past decade.[159] Half of the tax receipts from onshore drilling go to the state where the activity occurred.

155 EIA. "Natural Gas Dry Production." May 31, 2024. https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FPD_mmcf_a.htm.

156 "State Revenue and Spending." n.d. https://comptroller.texas.gov/transparency/revenue/.

157 DOE. "U.S. Oil and Natural Gas: Providing Energy Security and Supporting Our Quality of Life." September 2020. https://www.energy.gov/sites/prod/files/2020/10/f79/Natural%20Gas%20Benefits%20Report.pdf.

158 Texas Independent Producers and Royalty Owners Association. "2020 State of Energy Report." 2020. https://tipro.org/2020-state-of-energy-report/.

159 Congressional Research Service. "Revenues and Disbursements from Oil and Natural Gas Production on Federal Lands." September 22, 2020. https://crsreports.congress.gov/product/pdf/R/R46537.

2. Economic Impacts in Consuming States

According to a Council of Economic Advisers study in 2019, favorable oil and natural gas prices resulting from increased domestic oil and natural gas production provided $203 billion annual savings to U.S. consumers.[160] About 80% of the savings came from prices for natural gas that enabled electricity prices to remain lower than they would otherwise have been. The Council of Economic Advisers study estimated that the price of natural gas in 2018, without the shale revolution, would have been $7.79/Mcf, compared to the actual average $2.87/Mcf, a decline of 63%.

Constraints on constructing new natural gas pipelines have led to access challenges and higher natural gas pricing in certain regions—particularly in the northeastern United States—that have become segmented parts of the natural gas market. Despite a relatively short land distance between the Marcellus and Utica shale-production regions in Pennsylvania, Ohio, and West Virginia that are net exporters of natural gas, the northeastern United States has not seen significant expansions in natural gas pipeline infrastructure into and inside the region, despite significant capacity additions for natural gas generation.[161] In particular, there are concerns about energy availability during winter demand peaks, which are peaks for natural gas for heating and power generation in the region. This has caused short-term fuel substitution to coal and fuel oil in the power sector during these periods and the development of LNG import infrastructure to help meet peak regional demand. These LNG imports are sourced primarily from Trinidad and Tobago.[162]

FINDING 40: The U.S. natural gas supply chain has provided a sizable benefit for the

160 The White House, The Council of Economic Advisers. 2019. "The Value of U.S. Energy Innovation and Policies Supporting the Shale Revolution." https://trumpwhitehouse.archives.gov/wp-content/uploads/2019/10/The-Value-of-U.S.-Energy-Innovation-and-Policies-Supporting-the-Shale-Revolution.pdf.

161 ISO New England. "Natural Gas Infrastructure Constraints." n.d. https://www.iso-ne.com/about/what-we-do/in-depth/natural-gas-infrastructure-constraints.

162 EIA. "U.S. Natural Gas Imports by Country." May 31, 2024. https://www.eia.gov/dnav/ng/ng_move_impc_sl_a.htm.

U.S. economy in terms of jobs, GDP, and energy prices.

FINDING 41: Gas infrastructure buildout associated with shale gas production has included direct and indirect economic benefits for producing and consuming states; however, constraints on building pipeline infrastructure in some regions have increased risks of regional energy shortages during peak demand periods.

FINDING 42: The relative affordability of U.S. natural gas compared to global benchmarks has supported expansions of chemical and ammonia production industries in the past decade.

B. Foreign Policy Impacts—Energy and Economic Security

The development of shale and tight natural gas resources has led to the United States changing from a net importer of natural gas to the largest current LNG exporter. The development of U.S. LNG export capacity has played an important role in the global LNG market that will be explored in this section.

1. World LNG Markets and the U.S. LNG Role

Similar to crude oil, LNG is a globally traded commodity that is transported by ship from liquefaction facilities in exporting countries to regasification facilities in importing locations. According to Rapidian Energy Partners,[163] the global LNG import market in 2022 was divided between Asia (60%), Europe (30%), and the rest of the world (10%). In addition, the global LNG trade is two-thirds from long-term contracts and one-third from spot pricing models.

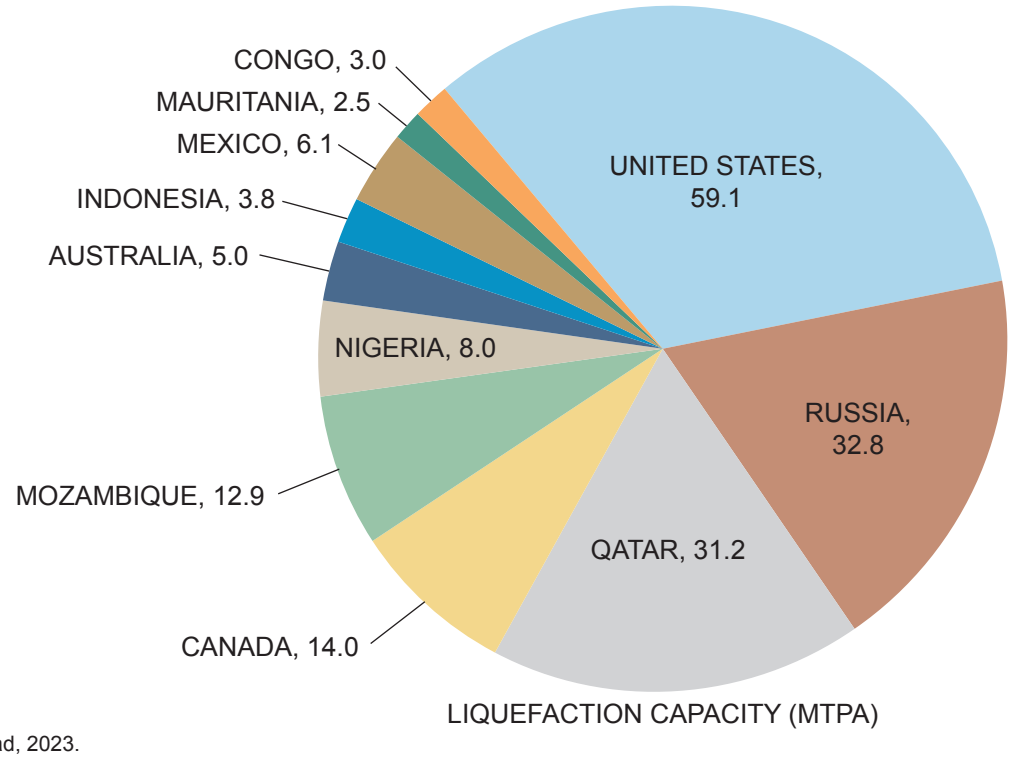
Historically, the scale and cost of development for LNG export facilities meant that long-term purchase contracts for significant portions of the facility production volumes were made ahead of final investment decisions, as part of the terms for financing the construction of the facility. The U.S. LNG export facilities that have been developed on the Gulf Coast in the last decade have tended to follow a different commercial model that allows for selling cargoes without firm destination clauses for where cargoes must be sent and allowing them to be marketed in any location. Benchmark spot pricing has allowed for easier price discovery mechanisms and demand signaling when regional gas markets are short on supply. LNG importers may prefer having access to both types of pricing models since there are supply and pricing risks associated with complete reliance on either structure. Many U.S.-based LNG contracting models also have volume flexibility with relatively low take-or-pay costs compared to long-term supply agreements in other jurisdictions, which may provide flexible options for LNG marketers during periods of low commodity prices, such as during 2020, when buyers of U.S. LNG elected to cancel cargoes that were not needed with decreased global energy demand at the time due to COVID-19. In addition, the U.S. natural gas market has been relatively insulated from global price increases, so buyers with LNG contracts linked to Henry Hub pricing have experienced less pricing volatility than those with international gas benchmarks or oil-linked pricing. Due to these contracting models, the increased availability of U.S. LNG exports has helped to reduce volatility in global LNG markets by providing flexibility and growing supply.

The United States began LNG export in 2016 and has sent more than 5,000 cargoes to 45 different countries around the world. While the U.S. became the largest LNG exporter in 2023,[164] the global market has three countries that each represent approximately 20% of the world export market: the United States, Qatar, and Australia.[165] The United States and Qatar both have

163 Munton, Alex. 2023. "European and Asian Energy Security in the Context of LNG." January. https://efifoundation.org/wp-content/uploads/sites/3/2023/05/White-Paper_Session-3_FINAL.pdf.

164 EIA. "U.S. Exports of Natural Gas Set a Record High in the First Half of 2023." October 4, 2023. https://www.eia.gov/todayinenergy/detail.php?id=60582#:~:text=In%20May%202023%2C%20U.S.%20net.

165 Munton, Alex. 2023. "European and Asian Energy Security in the Context of LNG." January. https://efifoundation.org/wp-content/uploads/sites/3/2023/05/White-Paper_Session-3_FINAL.pdf.



Source: Rystad, 2023.

Figure 1-35. *Global Approved Liquefaction Capacity by Market*

planned LNG export facilities that have reached a final investment decision (FID), are anticipated to come online before 2030, and would significantly expand the export capacity in those countries.[166] In particular, the U.S. is expected to contribute about half of the incremental LNG supply through 2026,[167] which would raise the United States to approximately 25% of the global supply, and represents up to 70% of the capacity additions expected in 2024. In 2023, U.S.-based LNG producers announced $39 billion in financing for new export projects. This incremental near-term capacity may be particularly important for European energy security, as discussed in the next section.

As shown in Figure 1-35, Russia also has substantial liquefaction capacity that has reached FID stage, including the Arctic 2 LNG project that is expected to commence production by 2024. Europe has continued to increase its purchases of Russian LNG despite reductions its purchases of Russian pipeline gas. LNG imports to Europe from Russia doubled between January 2021 (when Gazprom started restricting gas flows) to January 2023 and tripled since 2018. France, Spain, and Belgium have been the largest EU importers.[168] An EU proposal to ban Russian LNG deliveries was not adopted. Given the geopolitical concerns with Russian supply, there are differing opinions on expected completion dates for projects that have reached FID and the markets for such projects.

Continued expansion of U.S. LNG export capacity and flexible marketing terms are not universally supported by all stakeholders, who raise concerns around societal considerations and impacts and the GHG footprint of liquefaction facilities, which are discussed in Chapters

166 IGU. "2023 World LNG Report." July 12, 2023. https://igu.org/resources/lng2023-world-lng-report/.

167 IEA. 2023. "Medium-Term Gas Report 2023, Including the Gas Market Report, Q4-2023." https://iea.blob.core.windows.net/assets/f2cf36a9-fd9b-44e6-8659-c342027ff9ac/Medium-TermGasReport2023-IncludingtheGasMarketReportQ4-2023.pdf.

168 Robinson, Therese. "Europe Continues to Lean Heavily on Russian LNG Imports." September 21, 2023. Natural Gas Intelligence. https://www.naturalgasintel.com/europe-continues-to-lean-heavily-on-russian-lng-imports/.

U.S. LNG EXPORT CONTRACT STRUCTURE

Most international LNG contracts to date have been in the form of long-term sales and purchase agreements with a contract term of 20 years or more. In addition, these contracts have historically included a specific destination clause with the delivery point and restrictions on resale outside of the buyer's destination market. LNG contracts in the United States have typically taken a different structure and offered more flexibility to buyers in terms of contract term and destination clauses. In addition, U.S. LNG contracts are often priced relative to the Henry Hub natural gas price benchmark instead of international oil or gas pricing benchmarks.

The U.S. contract structure has influenced global LNG markets. The linkage to the Henry Hub benchmark has helped to make global pricing more competitive, and the destination flexibility has provided buyers with options to better manage their individual supply and demand balances by allowing volumes to more dynamically respond to changing market conditions.

2 and 4. Specifically on the topic of U.S. energy security and affordability, some stakeholders have expressed concerns that continued growth in U.S. export capacity could begin to affect U.S. natural gas prices, which have been historically lower and relatively insulated from global commodity pricing movements in natural gas. In 2023, the EIA released an issue-in-focus on the effects of different LNG export levels on the U.S. natural gas market.[169] The EIA report included a scenario with elevated global LNG prices and significant buildout in U.S. export capacity to meet that demand. For 2050, the EIA estimates that a high-end buildout case with a 77% increase in exports (48.2 Bcf/d) compared to the EIA reference case (27.3 Bcf/d) would increase the Henry Hub spot price from $3.77 (2022$/MMBtu) to $4.81, which is within the $2.23–$6.52 range of annual average pricing from 2018–2022. EIA modeling indicates that the higher prices would have some substitution impacts in the power sector, but relatively low impact on overall natural gas demand due to increased usage by liquefaction facilities. As recently as 2023,[170] the DOE concluded that increased U.S. LNG export projects are consistent with the U.S. public interest due to diversification of global LNG supplies and improved energy security for allies, despite considering these stakeholder concerns.

For example, in the first few months following the invasion of Ukraine by Russia, 74% of all U.S. produced LNG cargoes went to Europe, resulting, by March 2022, in northern EU LNG receiving terminals operating at more than 100% capacity and Poland's terminal operating at 114% capacity despite cutoffs of Russia gas supply.[171] Frequently, LNG cargoes that would have been destined for one buyer were resold or redirected to other buyers in response to market conditions, which had an influence beyond the overall volume of U.S. LNG exports. While there were discussions between government officials in the U.S. and EU about ensuring sufficient natural gas deliveries to Europe, much of the cargo redirection was driven by market forces and agreements between private-sector entities.

In addition, there is concern that global spot pricing and market flexibility with LNG may lead to the adoption of policies that increase GHG emissions in some jurisdictions, due to concerns around ability to obtain cargoes when prices are elevated. Several countries, particularly in Asia, have previously adopted natural gas and LNG imports as part of their dual strategy to increase energy access and reduce GHG emissions,

169 EIA. "Issues in Focus: Effects of Liquefied Natural Gas Exports on the U.S. Natural Gas Market." "EIA Annual Energy Outlook 2023." May 23, 2023. https://www.eia.gov/outlooks/aeo/IIF_LNG/.

170 DOE. "Order Granting Long-Term Authorization to Export Liquefied Natural Gas to Non-Free Trade Agreement Nations." DOE/FECM Order No. 4961. March 3, 2023. https://www.energy.gov/sites/default/files/2023-03/ord4961.pdf.

171 Mikulska, Anna B. and Steven R. Miles. "U.S. LNG 'Gas Lift' Floods European Terminals Ahead of Russia Gas Cutoff." Rice University's Baker Institute. May 2, 2022. https://www.bakerinstitute.org/research/us-lng-gaslift-floods-european-terminals-ahead-of-russia-gas-cutoff.

compared to a base case that utilizes coal for electric power or other fuels like biomass that have higher local air quality impacts, particularly when used for cooking in residential applications.

Global Energy Monitor reports that as of July 2023 some 350 GW of *new* coal-fired power plants are announced, prepermitted, or permitted, almost all in China and the developing world.[172] Of the top 11 countries planning new coal-fired power plants, seven have LNG import facilities that are not fully used to capacity. At the same time, there is increased anxiety from some countries in the developing world with regards to the accessibility and reliability of the LNG market for their situations, particularly if they mainly have spot market exposure in the short to medium term. For example, with increased costs and inability to obtain LNG cargoes in 2022, Bangladesh[173] and Pakistan[174] each announced medium-term plans to increase domestic coal production and coal-fired power generation in lieu of LNG, citing the need for affordable and reliable power for their citizens. Figure 1-36 shows that over an 80-year period, nations turn to coal (usually a domestic source) whenever there is turmoil in global energy markets.[175]

FINDING 43: The absence of destination clauses in many U.S. LNG contracts and link to Henry Hub pricing transformed the global LNG market by making it more competitive. This has had as large an impact on the global LNG market as the volume of U.S. exports has increased in the last decade.

2. Europe

Europe offers a recent example of U.S. LNG exports contributing to allies' energy security (Figure 1-37). Even in the period before Russia's invasion of Ukraine in early 2022, U.S. LNG exports had forced Gazprom to become increasingly flexible over time with its supply contracts. LNG from the United States and other global markets increased the competitiveness of gas markets in Europe by introducing alternative supply options to Russian natural gas.

Poland and Lithuania offer clear examples of increased competitiveness in European gas markets. A pipeline interconnection between Lithuania and Poland opened alternative gas supply routes into the country.[176] The Klaipeda terminal in Lithuania, which became operational at the end of 2014,[177] resulted in Gazprom significantly lowering the price of imported gas to the country. The average price Lithuania paid to Gazprom in 2016 for natural gas was €4,330/TJ; from 2014 to 2016, Lithuanian importers experienced a 46% price decrease from Gazprom. Lithuania saved more than €130 million in 2016 on the Russian gas it purchased due to diversification, so the price discounts from diversification more than offset the costs of the floating regasification terminal.[178]

This alternative source of natural gas supply became particularly important prior to and during the Russian invasion of Ukraine in February 2022, when Russia began to restrict pipeline gas supplies into major European markets, with an estimated decrease of 100 billion cubic meters annually. It should be noted that European gas and electricity prices began rising in 2021, well before

172 Global Energy Monitor. "Global Coal Plant Tracker." n.d. https://globalenergymonitor.org/projects/global-coal-plant-tracker/.

173 Rahman, Azizur and Eric Yep. "Bangladesh to Lean on More Coal Than Natural Gas in Power Generation to Curb Costs." S&P Global Commodity Insights. September 28, 2022. https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/092822-bangladesh-to-lean-on-more-coal-than-natural-gas-in-power-generation-to-curb-costs.

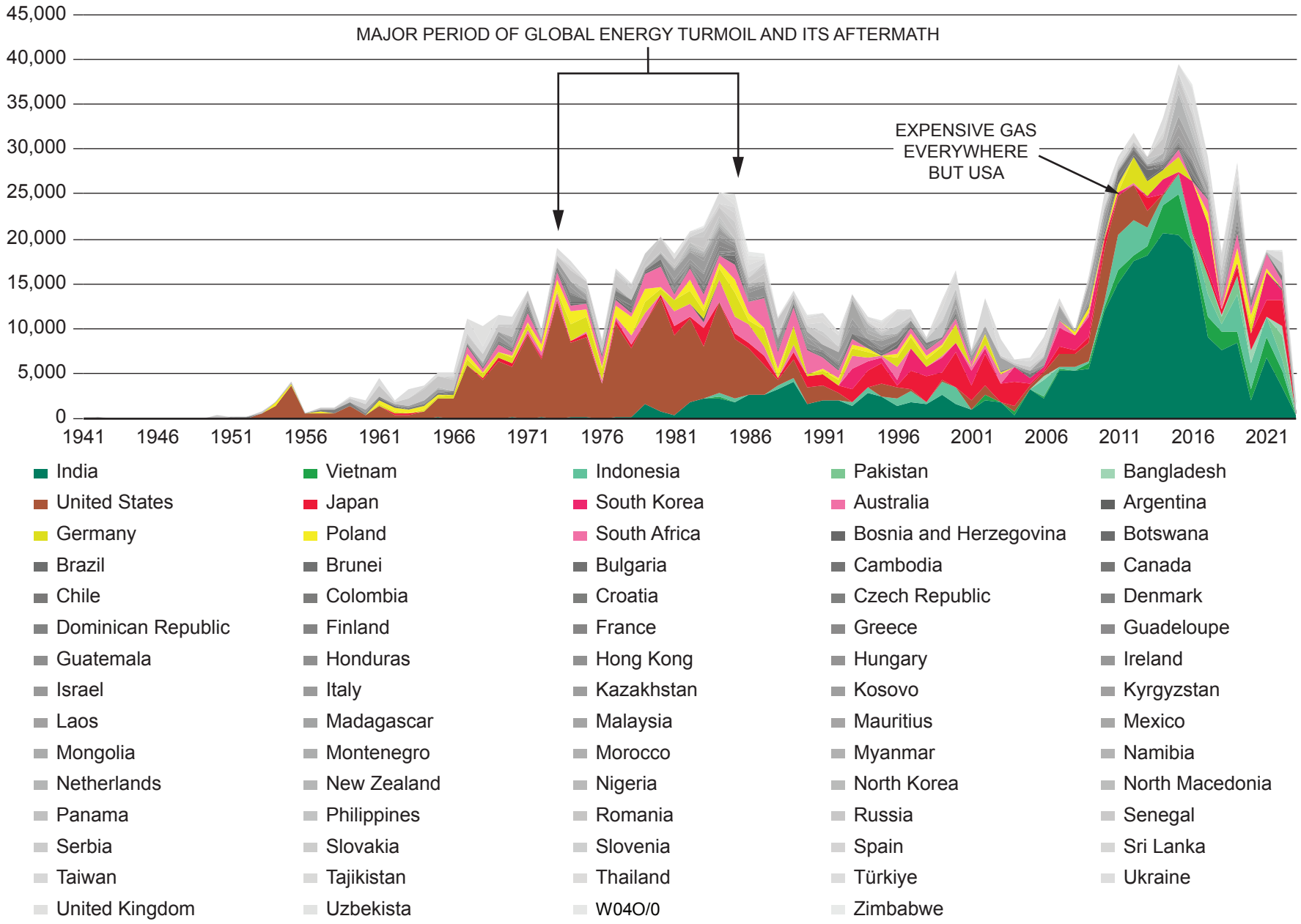
174 Peshimam, Gibran Naiyyar. "Exclusive: Pakistan Plans to Quadruple Domestic Coal-Fired Power, Move Away from Gas." Reuters. February 13, 2023. https://www.reuters.com/business/energy/pakistan-plans-quadruple-domestic-coal-fired-power-move-away-gas-2023-02-13.

175 Collins, Gabriel and Steven R. Miles. "Why Is Europe Not Replacing Russian Pipeline Gas with Long-Term LNG Contracts?" Rice University's Baker Institute. September 13, 2023. https://www.bakerinstitute.org/research/why-europe-not-replacing-russian-pipeline-gas-long-term-lng-contracts.

176 Sytas, Andrius. "Lithuania LNG Port Aims to be Baltic Hub, Double Flows." Reuters. January 21, 2019. https://www.reuters.com/article/lithuania-lng-idUSL8N1ZL2C9/.

177 KN Energies. Klaipėda LNG Terminal. n.d. https://www.kn.lt/en/our-activities/lng-terminals/klaipeda-lng-terminal/559.

178 Hinchey, Natalie. "The impact of securing alternative energy sources on Russian-European natural gas pricing." The Energy Journal, 2018. 39(2), 87-102. https://doi.org/10.5547/01956574.39.2.nhin.



Source: Collins, Gabriel, and Steven R. Miles, 2023, https://www.bakerinstitute.org/research/why-europe-not-replacing-russian-pipeline-gas-long-term-lng-contracts.

Figure 1-36. *Global Coal Power Plant Capacity Additions, Excluding China (MW Annually), 1941–January 2023*

Russia's invasion of Ukraine, as Russian started to curtail exports to Europe. When Russia invaded Ukraine in February 2022, it subsequently cut off most of its pipeline supplies to Europe.

While some of the energy gap in Europe was met through mandatory conservation measures (some of which furthered a deindustrialization process already underway), delayed closure of the Groningen gas field, and increased imports of gas from Norway and North Africa, approximately two-thirds of the incremental LNG deliveries in 2022 were from the United States,[179] which represented approximately half of the supply gap from Russian gas.[180] The flexibility in contracting terms and lack of destination clauses allowed for quick diversion of LNG cargoes based on market forces from Asia into European gas markets. U.S. officials, such as Secretary of State Blinken,[181] have credited the role of U.S. LNG in helping to ensure European energy security and blunting the intended energy market impacts of Russian gas supply reductions.

Importantly, the shift in LNG deliveries to Europe did not take years of debate or an act of Congress; market conditions combined with flexible contract terms allowed those volumes to flow to Europe. U.S. LNG producers ramped up production given high demand and market signals, operating at more than 105% of baseload capacity for 15 consecutive months, starting with Gazprom's drawdown of gas from Europe in early 2021.[182] In addition, the U.S. government worked behind the scenes to encourage allies in Asia to allow the volumes they had contracted to be redirected to Europe in the short term. As a result,[183] U.S. natural gas deliveries to Europe increased by more than 141% in 2022 and Europe became the primary destination for U.S. LNG exports (64%) that year. In 2022, LNG deliveries to Europe were larger than deliveries via pipeline sources to the continent, after rapid construction of new floating storage and import terminals.[184] European officials, such as European Commission President von der Leyen,[185] credited the increased deliveries of U.S. LNG with helping to strengthen European energy security and reducing dependency on Russian gas.

Through 2030, U.S. LNG facilities are expected to continue being a source of reliable supply to Europe, as the continent seeks to move away from Russian-supplied pipeline gas for energy security drivers. Over the longer term, there are differing opinions around the role of U.S. LNG in European energy markets. This includes stated policies that future natural gas demand levels overall in Europe should be less than today as part of NDCs to meet climate goals in the bloc. In particular, there appears to be hesitancy among European buyers to commit to longer-term supply contracts that would extend into the 2030s.[186] Europe currently purchases 60% of its LNG on a spot basis, meaning there is no commitment by a supplier—any supplier—to deliver longer than a couple months in the future, and there is no security as to either the source of the supply or the

179 IEA. 2023. "Global Gas Security Review 2023, Including the Gas Market Report, Q3-2023." https://iea.blob.core.windows.net/assets/f45a2340-8479-4585-b26e-ec5e9b14feca/GlobalGasSecurityReview2023IncludingtheGasMarketReportQ32023.pdf.

180 European Commission. 2023. "Quarterly Report on European Gas Markets – with Focus on Price Developments in 2022." Market Observatory for Energy, DG Energy, Volume 15 (Issue 4, Covering Fourth Quarter of 2022). https://energy.ec.europa.eu/system/files/2023-05/Quarterly%20Report%20on%20European%20Gas%20Markets%20report%20Q4%202022.pdf.

181 Blinken, Antony. "Secretary Antony J. Blinken Remarks Before U.S.-EU Energy Council Meeting." U.S. Department of State. April 4, 2023. https://www.state.gov/secretary-antony-j-blinken-remarks-before-u-s-eu-energy-council-meeting/.

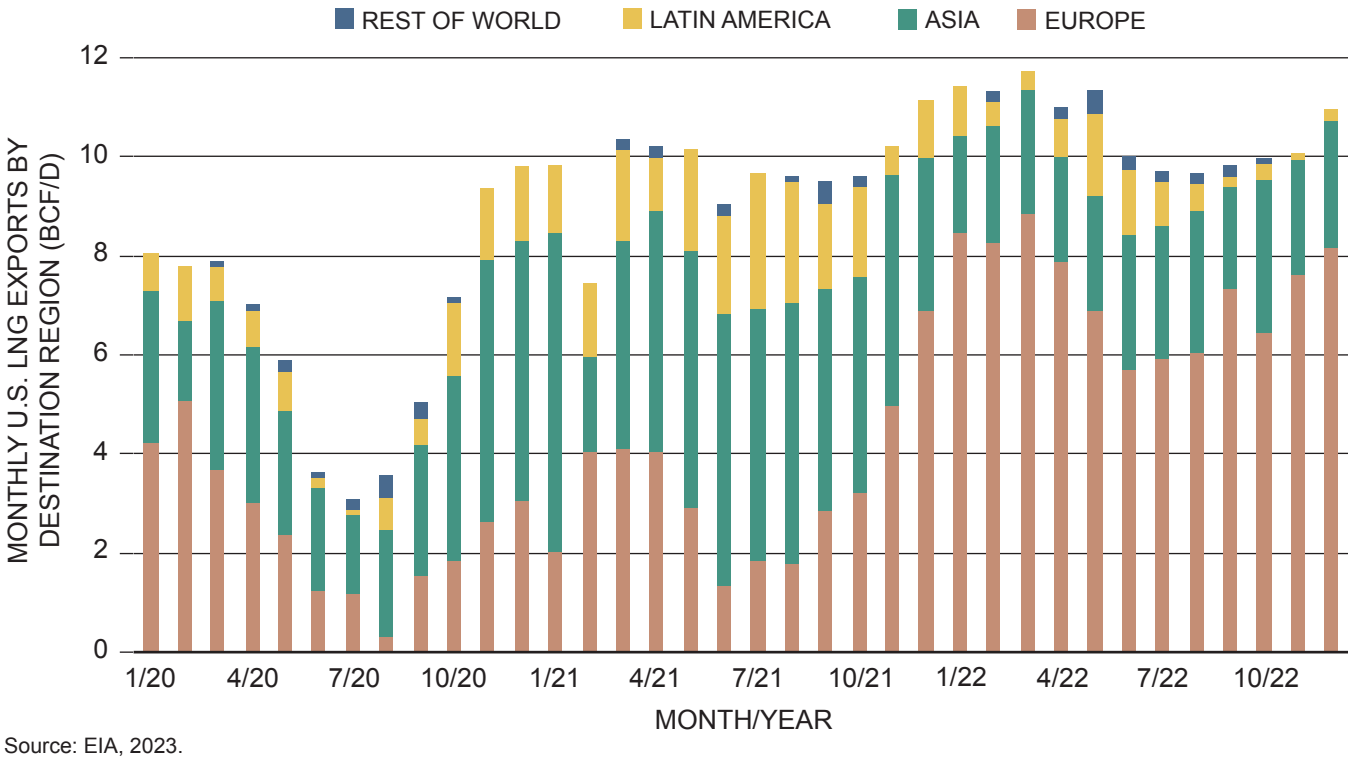
182 EIA. "The United States Became the World's Largest LNG Exporter in the First Half of 2022." July 25, 2022. https://www.eia.gov/todayinenergy/detail.php?id=53159.

183 Green, Mark. "Europe, Germany and the Continued Benefits of U.S. LNG Exports." American Petroleum Institute. July 5, 2023. https://www.api.org/news-policy-and-issues/blog/2023/07/05/europe-germany-and-the-continued-benefits-of-us-lng-exports#:~:text=For%20the%20first%20time%2C%20European.

184 Rocha, Priscila Azevedo and Anna Shiryaevskaya. "Europe's LNG Imports Overtake Pipeline Gas for First Time." Bloomberg. June 25, 2023; updated June 26, 2023. https://www.bloomberg.com/news/articles/2023-06-25/europe-s-lng-imports-overtake-pipeline-gas-for-first-time.

185 The White House. "Remarks by President Biden and European Commission President Ursula von der Leyen in Joint Press Statement." March 25, 2022. https://www.whitehouse.gov/briefing-room/speeches-remarks/2022/03/25/remarks-by-president-biden-and-european-commission-president-ursula-von-der-leyen-in-joint-press-statement/.

186 Collins, Gabriel and Steven R. Miles. "Why Is Europe Not Replacing Russian Pipeline Gas with Long-Term LNG Contracts?" Rice University's Baker Institute. September 13, 2023. https://www.bakerinstitute.org/research/why-europe-not-replacing-russian-pipeline-gas-long-term-lng-contracts.



Source: EIA, 2023.

Figure 1-37. *Monthly U.S. LNG Exports by Region*

price of LNG. Buyers may be relying on the ability to secure supplies on the short-term market, such as has been done during the Russian invasion of Ukraine, with stronger near-term demand signaling. In addition, there is concern that evolving European import regulations, including the application of potential but undefined requirements on methane emissions or other GHG attributes associated with imported cargoes, could cause renegotiations for longer-term deals. Better tools for estimating supply chain methane and carbon intensities and the passage of U.S.-based federal methane regulations could help with addressing buyer concerns around the GHG impacts of U.S.-based LNG imports.

As discussed in the prior section, several other LNG-importing countries have noted concerns with Europe's reliance on buying 60% of its LNG cargoes on a spot basis rather than signing long-term contracts that would support building new supply,[187] and the potential impacts on global affordability and reliability of the commodity.

FINDING 44: The U.S. position as the largest global exporter of LNG has had significant energy security benefits to Europe during the Russia-Ukraine conflict.

FINDING 45: Due to demand signals in Europe and flexible terms from U.S. facilities, Europe rapidly replaced Asia as the largest destination for U.S. exports, increasing by 141% in 2022 and accounting for two-thirds of the incremental natural gas deliveries into Europe.

FINDING 46: Europe continues to rely on spot market purchases for most of its LNG imports, which has influenced the global market for LNG, particularly in price-sensitive countries.

187 Collins, Gabriel and Steven R. Miles. "Why Is Europe Not Replacing Russian Pipeline Gas with Long-Term LNG Contracts?" Rice University's Baker Institute. September 13, 2023. https://www.bakerinstitute.org/research/why-europe-not-replacing-russian-pipeline-gas-long-term-lng-contracts.

3. China

China is also an active participant in the global LNG market. In 2021,[188] China surpassed Japan as the largest LNG buyer in Asia. While the U.S. only accounted for ~9% of LNG imports into China that year, there was year-over-year supply growth, particularly for spot market purchases due to a lowering of tariffs on U.S. LNG, from 25% to 10%. Contrasting European buyers that seemingly prefer the spot market for LNG cargoes, Chinese buyers have begun to sign longer-term delivery contracts, in the range of 15–20 years. As identified by the Baker Institute at Rice University, for the six-month period beginning in September 2021 and continuing through Russia's invasion of Ukraine, 11 Chinese entities, almost all state owned, bought more than 91% of all global LNG purchased *worldwide* under term deals[189] and more than twice what they had purchased in any prior full calendar year. Of these contracts, 75% of the volumes were sourced from the United States. According to Rapidian Energy Partners,[190] Chinese LNG import volumes decreased in 2022 due to lower energy demand during COVID lockdowns but has since recovered in 2023.

There are benefits to the United States of selling LNG to China pursuant to long-term contracts. Long-term agreements are a way to underpin new capacity additions and also increase trade linkage between the two countries in a strategically important sector. This may provide a constructive economic tie between China and the United States in a time of widespread bilateral tensions while helping China to meet its energy security goals and reducing the trade deficit of the United States. Given the buildout of coal-fired power generation in China, LNG substitution could also play a role in reducing country-level GHG emissions and helping to meet China's stated climate policy goals, though some analysts have noted that China may not pursue the same coal-to-gas switching strategy for power sector GHG emissions reductions due to the domestic availability of coal and rapid buildout of renewable energy generation capacity. Some energy market analysts are concerned that an overweighting of U.S. LNG supplies to China on longer-term contracts could create less flexibility in the spot market, on which Europe has chosen to rely for a substantial portion of its current natural gas supply.

4. Mexico

While China and Europe offer interesting examples of the ways that U.S. LNG exports have supported energy security, Mexico is an interesting case study around piped natural gas exports from the United States.[191] While Mexico has historically produced and exported significant hydrocarbon volumes and has substantial remaining reserves, natural gas production peaked in 2010 and has declined by 47%. At the same time, natural gas remains an important source of primary energy consumption in Mexico at 44% of the total. In 2022, 69% of natural gas consumed in Mexico was imported via pipelines from the United States, with notable volumes from recently completed pipelines drawing gas from the Permian Basin in western Texas and eastern New Mexico. In addition, U.S.-produced natural gas is expected to be a key source of supply for several LNG export projects under development in Mexico. Pacific Coast LNG export facilities would have shorter shipping distances to Asian markets than the U.S. Gulf Coast LNG facilities and would not require utilization of the Panama Canal.

IV. EMISSIONS PATHWAYS

As discussed in Section I, the United States has set its own economy-wide GHG emissions reduction targets for 2030 and 2050 and achievement of the Global Methane Pledge. Achievement of economy-wide goals will require emissions reductions from all sectors as well as continued advancement

188 EIA. "As of 2021, China Imports More Liquefied Natural Gas than Any Other Country." May 2, 2022. https://www.eia.gov/todayinenergy/detail.php?id=52258.

189 Miles, Steven R. and Gabriel B. Collins. "China's Big Gas Bet Raises Questions about Complicity with Russia." Foreign Policy. June 12, 2023. https://foreignpolicy.com/2023/06/12/china-natural-gas-russia-ukraine-war-energy/.

190 Munton, Alex. 2023. "European and Asian Energy Security in the Context of LNG." January. https://efifoundation.org/wp-content/uploads/sites/3/2023/05/White-Paper_Session-3_FINAL.pdf.

191 Rivera, Diego and Ira Joseph. "Lucrative Reward or Mounting Risk? Mexico's Growing Reliance on U.S. Gas." Center on Global Energy Policy at Columbia University. October 2023. https://www.energypolicy.columbia.edu/wp-content/uploads/2023/10/US-Mexico-Commentary_CGEP_101323.pdf.

in policies, technologies, and markets to support these activities.

This study is narrowly focused on the potential for direct GHG emissions reductions across the natural gas supply chain, excluding end use of natural gas. As with any assessment that discusses future emissions levels, there are significant uncertainties around the costs, pace, and availability of emissions reduction technologies and environment created for investments in scaled deployment of these technologies by policy and markets. The goal of these pathways around different emissions levels from the natural gas supply chain is to illustrate key areas for continued cowork between the natural gas industry, government, and other interested stakeholders to support collective emissions reduction goals and should not be viewed as definitive outcomes.

As affirmed in a recently published NPC report,[192] the United States oil and gas industry will be critical to meeting the net zero GHG emissions targets for the United States. The NPC believes that the energy transition should focus on the net reduction of GHG emissions. As such, there is the potential for negative emissions technologies, like direct air capture, or high-quality offsets to play a role in overall societal and natural-gas-sector GHG emissions reduction activities, although these are not discussed in-depth in this report. Thus, residual emissions remaining in any one sector of the economy can be compatible with an economy-wide net zero GHG emissions level, and the amount of future residual emissions in any segment will be a function of the ultimate availability and cost of different GHG emissions reduction technology options.

A. Emissions Pathways for This Study

Developing emissions pathways for the natural gas sector in the United States is a complex endeavor that requires simplification of complex interdependencies that may change over different time scales. For example, emissions reduction activities to 2030 are expected to be an overlapping mixture of voluntary reductions by the industry, multiple federal regulations on methane and flaring, state-level regulations, and market-driven mechanisms. Longer-term emissions levels for the sector will likely be influenced by advancements in policy, technology, and markets that are not fully characterized today, although they will inevitably be underpinned by the need for new and robust infrastructure that supports GHG emissions reductions.

Given the external focus on GHG emissions reduction from the U.S. natural gas sector, particularly with regards to methane, publicly available pathways that include the costs of GHG mitigation within natural gas supply chains are likely under studied relative to end-use sectors for fuels. Third-party analysis and associated pathways for the natural gas supply chain often make simplistic assumptions for the sector that don't necessarily correspond to how companies would make investment decisions to reduce emissions from their operations or may lack sufficient, emissions-source-specific detail that is needed to inform emissions reductions from assets and to connect other sources of information, such as the GHGI or life cycle models. For example, the Net Zero America pathways[193] mainly model methane reductions from the oil and gas sector as a function of lowered overall production levels for oil and gas, and the pathways for the oil and gas sector under the IEA[194] net zero scenario tend to focus on global production (versus U.S.-specific details) and deterministic assumptions around emissions reductions (i.e., 95% reduction in natural gas flaring) versus detailed discussions of how to achieve that.

This report outlines three different emissions pathways for the U.S. natural gas sector, which is broadly defined as including emissions estimates for natural gas systems up to end use, petroleum production, and abandoned wells within the

192 NPC. 2022. "Principles, and Oil & Gas Industry Initiatives and Technologies for Progressing to Net Zero - A Final Report of the NPC Committee on Short-Term Actions and Transition Strategies." December 14, 2022. https://www.energy.gov/sites/default/files/2023-01/STAS_v2_2022-12-16.pdf.

193 Princeton University. 2021. "Net-Zero America: Potential Pathways, Infrastructure, and Impacts." October 29, 2021. https://netzeroamerica.princeton.edu/the-report.

194 IEA. 2023. "Emissions from Oil and Gas Operations in Net Zero Transitions: A World Energy Outlook Special Report on the Oil and Gas Industry and COP28." https://iea.blob.core.windows.net/assets/2f65984e-73ee-40ba-a4d5-bb2e2c94cecb/EmissionsfromOilandGasOperationinNetZeroTransitions.pdf.

boundaries, based on 2020 data in the GHGI.[195] The NPC is not placing a probability around any emissions level or outcome in the future. Rather, this study seeks to use the discussion of pathways as an entry into discussions over priority sources for continued work by the industry, governments, and other partners toward reduction in GHG emissions intensity across the U.S. natural gas supply chain and to understand how these priorities may evolve over time. Note that all pathways also describe direct emissions reductions from the sector and not changes in GHG emissions from other sectors. For example, strategies that increase electrification could increase or decrease net national emissions, depending on the future CI of electricity generation in 2030 or 2050. Given in-flight GHG reduction policies for the electric power sector, estimating future-year emissions from electricity use is beyond the scope of these pathways.

Production and demand levels for future years in these pathways are based on the EIA reference case in the AEO2023.[196] AEO2023 includes projections from EIA on production, LNG export, and fuel utilization levels throughout the United States.

For 2050 emissions, three pathways are presented with different characteristics:

- Existing Policies (EP):
  - Includes reductions from suite of federal methane and flaring regulations
  - Includes an assumption that sector-average intensity performance reaches Methane Emissions Reduction Program benchmarks, like 0.2% of gas in the production sector
  - Uses EIA projections for natural gas supply chain fuel use, which assumes no additional technology or innovation breakthrough or market mechanism deployment
- Continued Reductions (CR):
  - Same as EP to 2030
  - Additional GHG emissions intensity reductions to 2050 that trend with current rates of improvement and levels of policy enablement
  - Technology gains for engine efficiency and compressor slip reductions, 50% CCS deployment for acid gas plants
  - Does not assume additional market mechanisms
- Technology, Innovation, and Policy (TIP):
  - Same as EP to 2030 and all CR initiatives
  - Policy and voluntary efforts shift to CO_2 as CH_4 is reduced
  - Technology-enabled advancements in key areas (increased electrification, CCS for all acid gas and LNG plants, further deployment of technologies to reduce compressor slip)
  - Market mechanisms support CCS and electrification

As discussed in prior sections, there are existing voluntary reduction programs, including corporate-level efforts to reduce GHG emissions that may be beyond regulatory requirements in a specific jurisdiction. Corporate voluntary commitments have not been numerically assessed in these pathways and such programs could yield additional GHG reductions that are not covered in pathways in this study.

In addition, pathways used in the analysis are based on the EIA AEO2023 reference case. Chapter 5 discusses other cases and third-party analyses in depth, which include a variety of different assumptions for the size and disposition of the natural gas in the United States. Higher or lower throughput or activity levels for the U.S. natural gas supply chain would have an influence on its GHG emissions and GHG intensities. Regardless of levels for supply and demand, reducing the GHG emissions intensity of the natural gas supply chain will support the role of this commodity, including for worldwide energy security that is described in-depth earlier in this chapter.

Due to the starting point for the Global Methane Pledge, the baseline emissions inventory used in this work is 2020 emissions from the GHGI, including emissions from natural gas systems, petroleum systems, abandoned oil and gas wells,

195 EPA. 2023. "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021." https://www.epa.gov/system/files/documents/2023-04/US-GHG-Inventory-2023-Main-Text.pdf.

196 EIA. "Annual Energy Outlook 2023." March 16, 2023. https://www.eia.gov/outlooks/aeo/.

and natural gas combustion for use in the supply chain, which are described in detail in Section I of this chapter. It should be noted that oil and gas industry activity levels were lower in 2020, due to effects of the COVID-19 pandemic, but the provision of 2021 data under the GHGI alleviated concerns over its representativeness of sectoral emissions trends. Compared to 2020, 2021 emissions were ~10% lower in petroleum systems due to decreased rates of associated gas flaring and venting and ~2% higher in natural gas systems. Thus, the choice of 2020 as a base year is unlikely to negatively influence the emissions level pathways to 2030 and 2050 in this work.

FINDING 47: For all levels of supply and demand, reducing the natural gas supply chain carbon intensity will play an important role in allowing this commodity to contribute to worldwide energy security.

B. Methane Emissions Pathways

In the United States, methane emissions from the oil and gas sector are receiving growing policy interest through regulations at the state and federal levels as well as in the voluntary reduction programs from operators, and thus, are expected to see a higher degree of reduction from current baselines this decade compared to carbon dioxide emissions. While there are a number of different initiatives that are likely to lead to methane emissions reductions in the sector, this study focuses on the stated source-specific reduction potential of a suite of federal methane programs to 2030, including: 2022 proposed methane rules from EPA and PHMSA, the methane fee component of the Inflation Reduction Act, and funding to plug orphan wells under the IIJA–and additional technology-driven reductions, primarily around engine slip, to 2050. Natural gas production rate assumptions underlying 2030 and 2050 pathways are based on the EIA AEO2023 reference case, which includes increased U.S. production in 2030 and 2050, relative to 2020.

Based on regulatory emissions reduction estimates in proposed rules and an assumption that, if needed, additional investments will be made in each natural gas supply chain segment such that average emissions are below the emissions fee thresholds in the IRA (Figure 1-38), an ~63% reduction in methane emissions is estimated for this study by 2030, with reductions driven by a near phaseout of natural gas venting for pneumatic controllers and pumps, changes to control technology requirements for compressor seals and packing, and the implementation of LDAR programs in most supply chain segments. For 2050, scenarios range from a 59%–70% reduction from the 2020 baseline. Increased emissions in the 2050 EP Pathway relative to 2030 is a function of the larger natural gas production volumes in 2050, based on EIA reference case scenario production estimates.

Estimated at ~26% of residual methane emissions in the 2050-EP Pathway, slip associated with natural gas combustion in engines remains a key category for further technological development, such as the DOE-led Advanced Research Projects Agency – Energy (ARPA-E) REMEDY[197] program that seeks to develop technologies to increase destruction efficiency to greater than 99.5% for this application. Rates of adoptions of electric compressors (which eliminate this emissions source), the ratio of lean-burn to rich-burn natural gas engines, and deployment of methane reduction technologies for lean-burn engines, would also influence sector-wide emissions from this source in 2050.[198]

In this study, the 2030 pathway includes an assumption that national average supply chain segment intensities meet the thresholds identified in the IRA for the methane fee, such that, on average, operators would not be paying emissions fees by the end of the decade due to the implementation of methane reduction projects. Several of the sector-specific thresholds in the IRA, such as 0.2% for the production sector, are consistent with near-zero methane intensity voluntary pledges from operators. Given the growth in natural gas production assumed in the EIA AEO2023 reference case that underpins 2050 scenarios,

197 REMEDY– Reducing Emissions of Methane Every Day of the Year. Program released April 8, 2021. https://arpa-e.energy.gov/technologies/programs/remedy.

198 Hiltner, Joel. "Unburned Hydrocarbon Emissions from Lean Burn Natural Gas Engines – Sources and Solutions," CIMAC Congress, June 6-10, 2016.

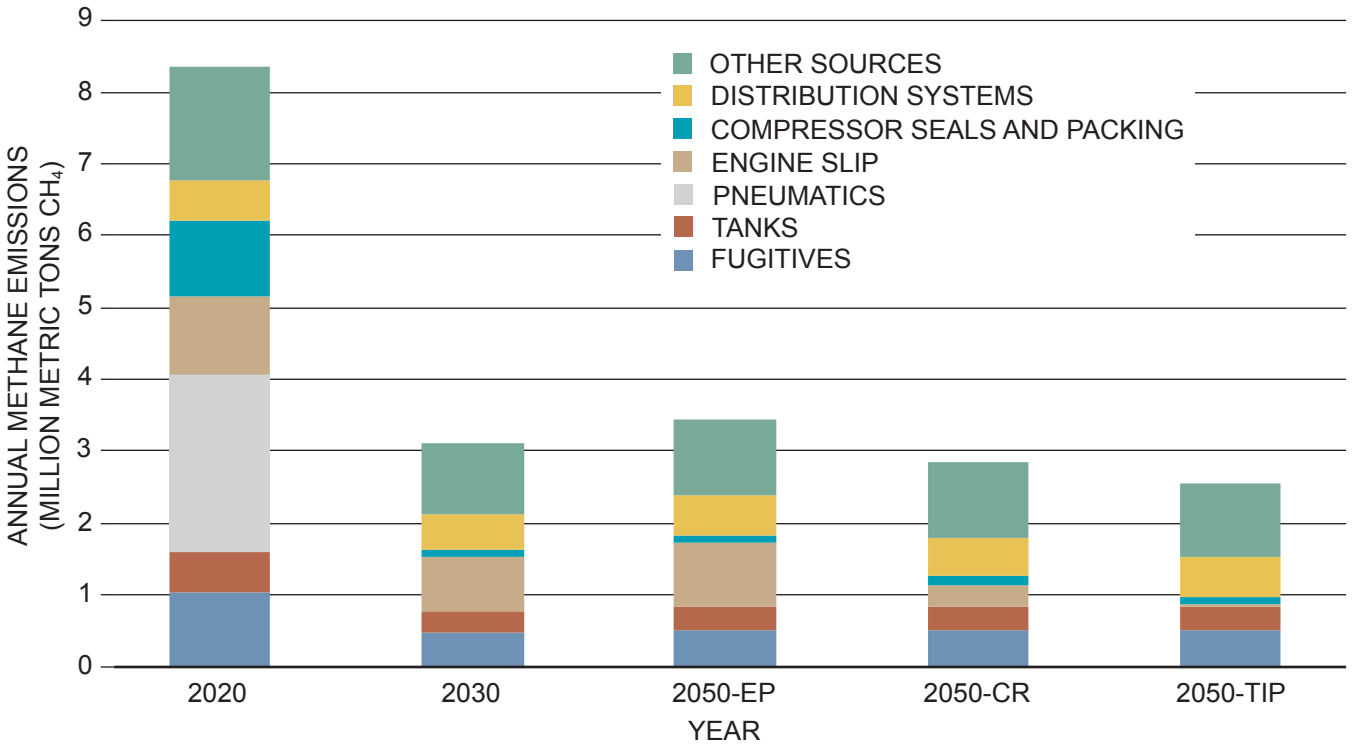


Figure 1-38. *Source Breakdown of Methane Emissions Pathways in This Study*

absolute methane emissions across pathways are shown to be relatively flat to 2050. On an unallocated intensity basis, these would range from 0.3%–0.4% of gas production performance across the entire U.S. natural gas supply chain, which would be consistent with near-zero methane intensity levels added for individual segments.

Good policy includes periodic reevaluation of reasonable timelines. Based on proposed timelines for implementation, particularly for existing sources, and the need to develop measurement-informed inventories, which is discussed in detail in Chapter 3, 2030 would be a reasonable timeline to reevaluate methane emissions levels from the natural gas supply chain, including updates to voluntary and regulatory reduction programs based on the latest information about sources of emissions, reduction options, and information from scientific measurement studies. This may lead to the identification of additional methane reduction opportunities—beyond lean-burn engine slip—that could be implemented to further reduce emissions in the natural gas supply chain. Such an effort should include multiple stakeholders, such as industry, regulators, and civil society organizations, and incorporate the latest information on measurement-informed inventories.

A common critique of the GHGI and other methane reporting methodologies based mainly on activity data and emissions factors is that these inventories may not account for all emissions sources present, especially super-emitters, which are low-probability but high-emissions-rate events that may form a disproportionate number of total emissions from the sector. Figure 1-39 illustrates the potential impact of assuming that methane emissions from the oil and gas sector are higher than current baseline emissions as well as the assumption that emissions are to decrease by 90%–95% as a result of increased LDAR activities in the sector, increased availability of low-cost third-party monitoring data from technologies like satellites, and the potential inclusion of portions of these emissions in methane fee calculations under the IRA. A higher baseline for methane emissions would mean the potential for a greater overall reduction in emissions by 2030, particularly if noninventoried sources are found to be easily detectable and prove addressable going forward.

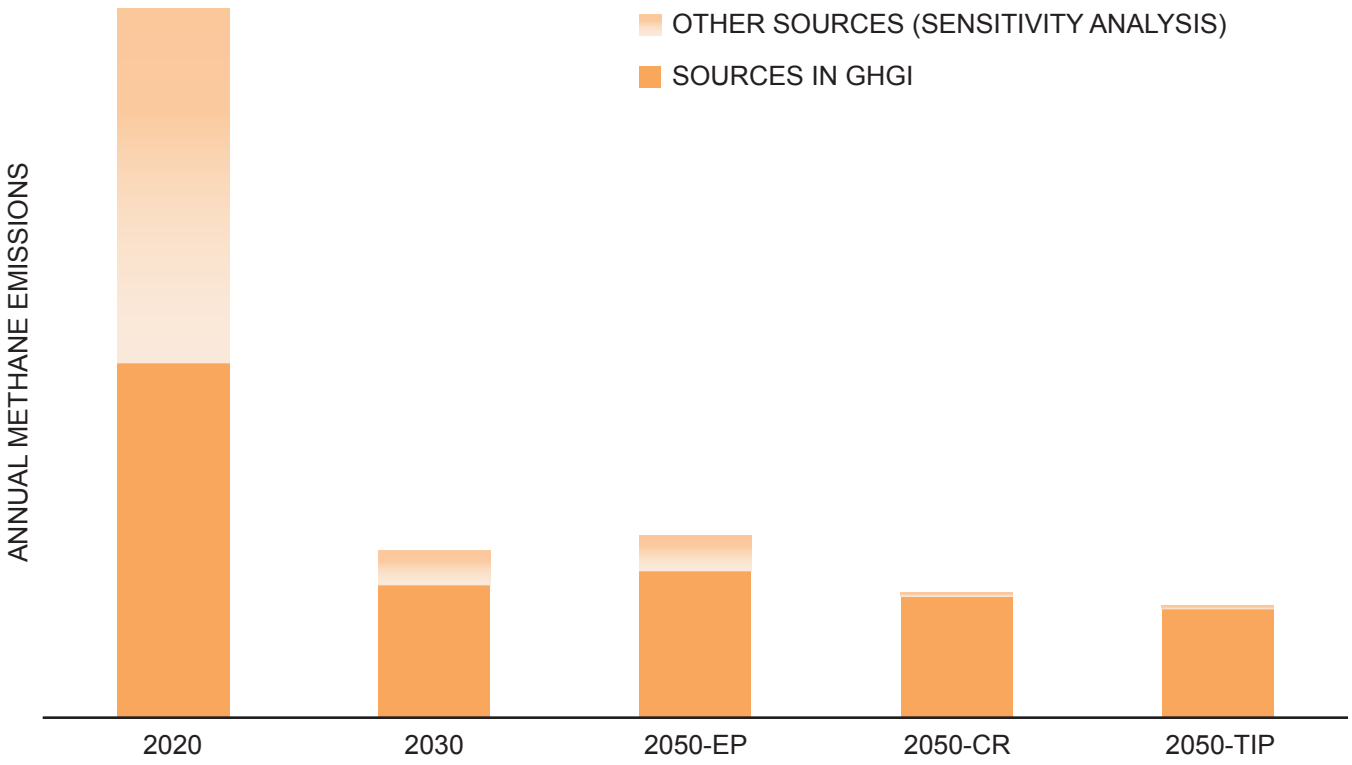


Figure 1-39. *Sensitivity Analysis for Methane Reduction Pathways with a Higher Baseline Emissions Rate from Sources That Are Currently Not Included in Emissions Inventories*

FINDING 48: **Engine methane slip is expected to remain a key methane emissions source after 2030. Mitigation options for the industry include compressor electrification, rich-burn gas engines, lower-methane lean-burn engines, and retrofits to existing lean-burn engines under development in programs like DOE's Reducing Emissions of Methane Every Day of the Year (REMEDY) effort.**

RECOMMENDATION 15: ***The NPC recommends that a multistakeholder taskforce be established in the late 2020s to evaluate further methane emissions reduction opportunities in the sector.***

C. Carbon Dioxide Emissions Pathways

Consistent with IPCC guidelines for country-level GHG reporting to UNFCCC, the EPA GHGI includes noncombustion (i.e., fugitives, flaring, and venting) emissions sources in the oil and gas sector but does not specifically break out emissions associated with fuel use, mainly natural gas, throughout the oil and gas supply chain. EPA bases its overall estimates for GHG emissions from natural gas use on data collected by EIA. EIA data for natural gas use in its historic and projected data includes lease and plant fuel, which encompasses production through gas processing in the supply chain, and pipeline and distribution use, which includes natural gas use in transmission, distribution, and for LNG liquefaction. Baseline emissions in 2020 include natural gas combustion and carbon dioxide emissions tracked for noncombustion sources (like the venting of reservoir carbon dioxide at gas processing plants to remove acid gas to meet pipeline specifications).

Sources of carbon dioxide emissions across the natural gas supply chain differ from the types of sources associated with methane emissions (Figure 1-40). Fuel use by plants (Lease and Plant, Pipeline and Distribution, and LNG) makes up more than 70% of baseline emissions from the sector and provides necessary energy for compression, heat,

drilling and on-site power generation throughout the sector. It should be noted that emissions pathways for 2030 and 2050-EP, which show increased carbon dioxide emissions relative to the 2020 baseline, directly use the AEO2023 reference case for fuel use in the natural gas supply chain. Reference case extrapolations in AEO2023 are based on recent average intensities and do not include any assumptions for increased energy efficiency or lower-carbon-intensity technology substitutions. The other two 2050 emissions pathways include assumptions with different degrees of GHG emissions intensity reduction in the sector and rates of implementation for CCS and electrification within the natural gas supply chain. It should also be noted that state-level regulations intended to reduce overall GHG emissions from their oil and gas sector, such as in Colorado and California, are not included in the NPC emissions pathways or scenarios from EIA in AEO2023.

There is significant uncertainty around estimates contained within these pathways due to uncertainties in the cost and deployment rate of GHG emissions reduction technologies and the availability and ability to permit infrastructure. For the same emissions source, there are potentially multiple options for reducing GHG emissions, each with different cost profiles and tradeoffs. As an example, LNG plants utilize fuel to produce electricity and drive compressors as part of the process of supercooling natural gas that enters the plant into a liquid form. The default assumption in EIA AEO2023 across all years is that 8.1% of the intake natural gas at the plant is used as fuel in the liquefaction process and that fuel use will directly grow with U.S. LNG export volumes. Abatement options include smaller reductions from energy efficiency improvements in the process and larger reductions associated with high-cost capital investments in CCS, replacement of gas-driven with electric compressors with a tie to lower-carbon power sources, or sourcing of higher-cost fuel feedstocks like hydrogen. Hydrogen and electrification would lead to direct emissions reductions from the LNG plants, but national-level GHG reductions from the change would be dependent on the supply chain

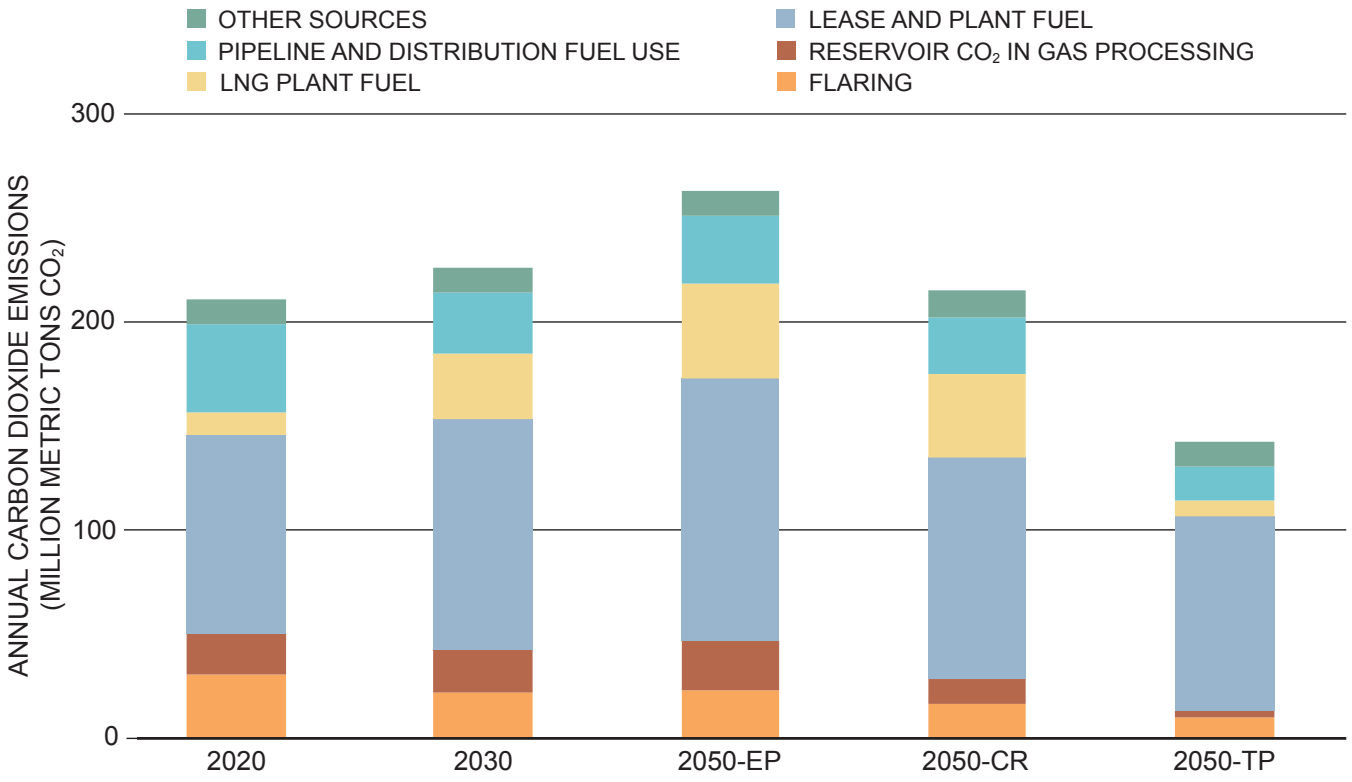


Figure 1-40. *Source Breakdown of Carbon Dioxide Emissions Pathways in This Study*

GHG intensity for the provided energy. U.S. LNG export facilities have discussed the inclusion of several of these GHG reduction elements in their operations, but projects have yet to be completed to understand the cost and operational impacts. Changes in technology costs and policy may eventually favor one approach over another for GHG reduction.

Consistent with prior NPC work on CCS,[199] reservoir carbon dioxide that is separated from hydrocarbon components of natural gas at gas processing plants in an acid gas recovery unit are a concentrated source of carbon dioxide emissions for which deployment of capture technologies may be lower cost than other applications, like natural gas-fired power generation. The 2050-CR and 2050-TIP pathways include different degrees of CCS deployment on this point source.

In the 2050-EP scenario, fuel use in the supply chain is ~77% of carbon dioxide emissions in the natural gas supply chain and is vital for continued affordable and reliable operations in the sector. Natural gas is used throughout the supply chain to power compressors and other site operations, provide heat to prevent freezing in the process and enable efficient separation of different hydrocarbon components, and to provide energy for drilling activities. As shown in the 2050-CR and 2050-TIP, there is potential for GHG emissions reductions from this source but also the need for continued technology and policy improvements.

For example, some elements in the natural gas supply chain where natural gas is currently used for energy purposes can be electrified. The GHG emissions reductions associated with electrification strategies could lead to increased or decreased GHG emissions, depending on the CI of the associated electric grid, relative to natural gas combustion for local energy use at site. Particularly for larger production areas like the Permian Basin, operators have begun to examine the feasibility of compressor electrification with low-carbon power as part of their company GHG emissions reduction strategies.[200] The use of electric compressors is feasible, but operators have noted multiyear delays for obtaining electric (versus gas-driven) compressors and for electric utilities to be able to permit and hook up to power substations in remote areas. As access to compression is constantly needed to move gas to market and avoid flaring, the reliability of grids in remote areas, particularly in areas where the fraction of dispatchable power is decreasing, remains a concern for some operators in making this switch. Additional investments in natural gas power generation could help to increase the dispatchable portion of power generation in the grid. When combined with CCS, natural gas power generation could also provide significant reductions in the CI of the U.S. power sector.

Federal resources for grid access and reliability studies in key production regions and into options for local power generation in smaller basins could help to enable a higher degree of electrification of compression in the natural gas supply chain. Other current field uses for natural gas, like the provision of heat and power generation in remote areas, may be hard to electrify and may warrant different GHG emissions abatement approaches over the longer term.

FINDING 49: **Near-term GHG emissions reductions from the natural gas supply chain will likely be driven by a combination of regulation and voluntary actions and are likely to focus on reduction of methane and flaring. Stable federal policy and state uptake is needed to obtain these near-term reductions.**

FINDING 50: **Longer-term GHG emissions reductions will require durable, technology-neutral policy, supportive and reliable infrastructure, and efficient, effective, and predictable permitting to incentivize capital investment and adoption of market mechanisms.**

199 NPC. 2019. "Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage." 2019. https://dualchallenge.npc.org/.

200 Smith, Curtis and Min Rao. 2023. "Electrifying the Permian Basin," Proceedings of the 11th Unconventional Resources Technology Conference. https://doi.org/10.15530/urtec-2023-3859345.

FINDING 51: The pace of reductions in GHG emissions associated with energy use in the sector will be influenced by the connectivity, reliability, and carbon intensity of the electric grid.

RECOMMENDATION 16: *The NPC recommends that DOE Office of Fossil Energy and Carbon Management partner with the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation to study ways to increase grid reliability as the non-dispatchable portion of electricity generation increases to help enable electrification across the natural gas supply chain.*

D. Technology Research

Based on EPA estimates in the GHGI, the use of natural gas as fuel for compression, heat, and power, including drilling/completion activities, represented ~34% of U.S. natural gas supply chain GHG emissions (~150 MMT CO_2e) in 2020. Due to future reductions in methane and flaring emissions across the natural gas supply chain, emissions pathways in this NPC study suggest that supply chain natural gas combustion could represent 50%–60% of emissions in 2030 and 2050. Similar to current DOE programs supporting research, development, and deployment activities for methane measurement and control technologies, there is an opportunity for DOE to develop a new program to support lower-carbon-intensity technologies to provide these needed functions in the U.S. natural gas industry.

RECOMMENDATION 17: *The NPC recommends that the DOE Office of Fossil Energy and Carbon Management undertake new research, development, and deployment programs that are focused on affordable and reliable technology options that could reduce the carbon dioxide intensity of energy use throughout the natural gas supply chain for compression, heat, and power activities.*

Such a program is likely to include projects at different technology readiness levels, but should consider the following focal areas to develop approaches to a high technology readiness level and demonstrate them via field deployments:

Electrification and Energy Efficiency:

- **Behind-the-meter generation of low carbon intensity baseload power at the 1 MW–15 MW scale:** For current applications where natural gas is used to provide energy for critical supply chain services like compression, replacement options like electrification would require access to reliable and continuous power for proper functioning. Natural gas compression often occurs in remote regions, for which reliable grid connections are challenging. Baseload power packages in the 1 MW–15 MW range, such as geothermal, micro modular nuclear, energy storage, or other technologies could help to support electrification of compression in remote regions.
- **Improvements to heat and power integration:** There is waste heat associated with natural gas combustion across the natural gas supply chain. Funding for demonstration cases for modular units for utilizing waste heat for other process sources, like heater treaters or separator heaters, or improving compressor efficiency could help to increase adoption of waste heat recovery processes in the natural gas supply chain.
- **Opportunities for cost reduction for electric compression:** Electric compressors have an upfront capital cost for connecting last-mile transmission infrastructure to the grid and the compressor units. A DOE program to analyze key inputs and prioritize projects to reduce costs/timelines associated with electric compression packages could increase the potential for this GHG emissions reduction lever to be deployed, particularly among less capitalized operators.

CCS and Hydrogen:

- **Modular CCS capture units for 3%–4% CO_2 concentration sources:** Flue gas from natural gas combustion contains a relatively low concentration of dioxide, which increases the challenges associated with capturing such volumes

in CCS activities, with respect to more concentrated sources. Funding for proof-of-concept projects in the 100,000–500,000 ton per year range and associated last-mile infrastructure would support technology advancements and may provide additional options for reducing the CI of combustion sources in the natural gas supply chain.

- **Hydrogen in 1 MW–25 MW applications:** Low carbon intensity hydrogen supply chains offer the potential for GHG emissions reduction for compression, heat, and power applications. Much of the research to date on blending with natural gas or direct hydrogen firing of combustion equipment has occurred in larger engine and turbine sizes for industrial applications. Applications in the natural gas supply chain are smaller in scale. DOE should fund work to characterize emissions profiles and conversion capabilities for 1 MW–25 MW applications and last-mile infrastructure studies to understand the potential for hydrogen in this application.

E. Policy Enablement

Many of the GHG emissions reductions discussed in these pathways, particularly for carbon dioxide, would necessitate large capital investments from operators in the natural gas supply chain and supportive policies that spur investment and allow for permitting of the needed infrastructure. In the near term, incentives can be an effective way to spur initial deployments; however, market-based approaches are preferrable over the long term as the most economically efficient way to reduce emissions, compared to mandates or incentives.

For methane emissions, many of the modeled emissions reductions in this work are based on proposed federal methane regulations. Methane reductions associated with final rules could be larger or smaller than what is modeled in this study, depending on the form, function, and implementation of the final proposals over the course of this decade. Changes to the emissions reduction elements of the rules would impact the realization of these methane emissions reductions from the natural gas supply chain.

An economy-wide carbon price would be the most economically efficient method of reducing carbon dioxide emissions, including from the natural gas supply chain. A predictable price would allow for economic analysis of emissions reduction projects and would align with typical corporate planning and project evaluation processes in the industry. Currently, it is challenging to assess the association between a specific carbon price and GHG emissions levels from the natural gas supply chain for a few reasons. First, common carbon pricing models for the United States often focus on end-use sectors in the economy, e.g., transport or power generation, and do not necessarily have detailed marginal abatement cost curves for carbon dioxide reductions from the fuel production supply chains that would be needed to understand the related emissions levels in the supply chain. Second, emissions levels for the natural gas supply chain would have some relationship with the overall demand for oil and natural gas under the scenario being examined. Directionally, a price on carbon dioxide emissions would increase the number of emissions reduction projects that would be considered economically attractive and reduce the CI of the supply chain.

Within carbon pricing programs, there are different policy options for non-carbon dioxide emissions, including methane emissions from natural gas supply chains. Markets like California and Norway include at least some of the methane emissions from this sector in the program while others, like the European Union, have historically excluded the source from the market-based program and focused instead on command-and-control requirements. Pricing of methane emissions would require robust measurement, report, and verification frameworks with defined methodologies that provide certainty on how emissions are assessed under the program and that would allow for facilities under the program to reduce their assessed emissions through changes in facility design and operations.

The IRA of 2022 includes a charge on applicable methane emissions above sector-specific thresholds from larger facilities that report emissions to the U.S. GHGRP that ranges from $900 in 2024 to $1,500 for 2026 onward per metric ton of methane. This range of methane emissions fees

corresponds to $32–$54 per metric ton of carbon dioxide equivalent emissions, using the GWP of 28 used in this work.

As the United States does not currently have a national price on carbon emissions, there are other potential market-based mechanisms that could provide reductions in GHG emissions from the natural gas supply chain. With appropriate MRV mechanisms in place, incentives like tax credits for voluntary GHG emissions abatement actions or certified gas markets could provide a pathway for reducing costs associated with GHG emissions reductions in the natural gas supply chain. Particularly for less capitalized operators, low-interest government financing and grants for GHG reduction projects and technology trials, such as those in the Methane Emissions Reduction Program in the Inflation Reduction Act of 2022, could be an additional model for continued GHG abatement in the sector. Tax incentives, like 45Q for CCS, could also play a role in reducing GHG emissions in the sector. More details on market mechanisms are available in Chapter 5.

F. Relationship to U.S. Pledges

The Global Methane Pledge seeks a global 30% absolute reduction in global anthropogenic methane emissions across all sectors by 2030, relative to a 2020 baseline. The 2030 emissions pathway in this study includes a ~63% reduction in methane emissions from in-scope sources, including the natural gas supply chain, oil production, and abandoned wells. Based on a 2020 baseline of 742.2 MMT CO_2e for U.S. total methane emissions in the latest GHGI,[201] reductions associated with the 2030 pathway would represent a ~20% reduction in U.S. absolute methane emissions and contribute approximately two-thirds of the national methane reductions for the Global Methane Pledge. Policy and methane mitigation technology advancements to reduce emissions across other sectors will be necessary to achieve a 30% economy-wide reduction under the Global Methane Pledge, assuming that the United States intends such a reduction as part of its commitment under the program.

Figure 1-41 includes an estimate of overall GHG emissions for this study scope with the same GWP100 factors that EPA uses in its GHGI and for UNFCCC reporting toward its national emissions goals. The nationally determined contribution for the United States under the Paris Agreement[202] includes a 50%–52% reduction in economy-wide net GHG emissions in 2030, relative to a 2005 baseline. For 2020, the EPA[203] estimates an economy-wide net emissions reduction of 22% relative to the 2005 baseline across all sources. For the natural gas supply chain, reductions modeled in this study, particularly in methane emissions, would equate to a ~2% reduction in national net GHG emissions. On an economy-wide net basis, the natural gas industry could enable additional reductions through the displacement of more carbon-intensive fuel sources, like coal-fired power generation, though estimating future fuel switching is outside the scope of this work. Conceptually, the use of a GWP20 would raise the baseline carbon dioxide equivalent emissions estimates for methane-emitting sectors, like the natural gas supply chain, and overall U.S. net GHG emissions. With GWP20, methane-focused GHG reductions would be weighted more heavily than with GWP100, potentially leading to larger percentages of GHG reductions in sectors with methane reductions.

The range of 2050 emissions pathways examined in this study would represent reductions of 1%–3% relative to 2005 U.S. net emissions. From a policy perspective, residual emissions in any one sector are inherently compatible with a net zero GHG emissions societal pathway because negative emissions technologies could be used to offset. Such technologies could range from nature-based solutions to engineered solutions like direct air capture. The U.S. oil and gas sector is uniquely

201 EPA. 2023. "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2021." Table 2-8. https://www.epa.gov/system/files/documents/2023-04/US-GHG-Inventory-2023-Main-Text.pdf.

202 UNFCCC. "The United States of America Nationally Determined Contribution: Reducing Greenhouse Gases in the United States: A 2030 Emissions Target." 2021. https://unfccc.int/sites/default/files/NDC/2022-06/United%20States%20NDC%20April%2021%202021%20Final.pdf.

203 EPA. 2023. "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2021." Table 2-8. https://www.epa.gov/system/files/documents/2023-04/US-GHG-Inventory-2023-Main-Text.pdf.

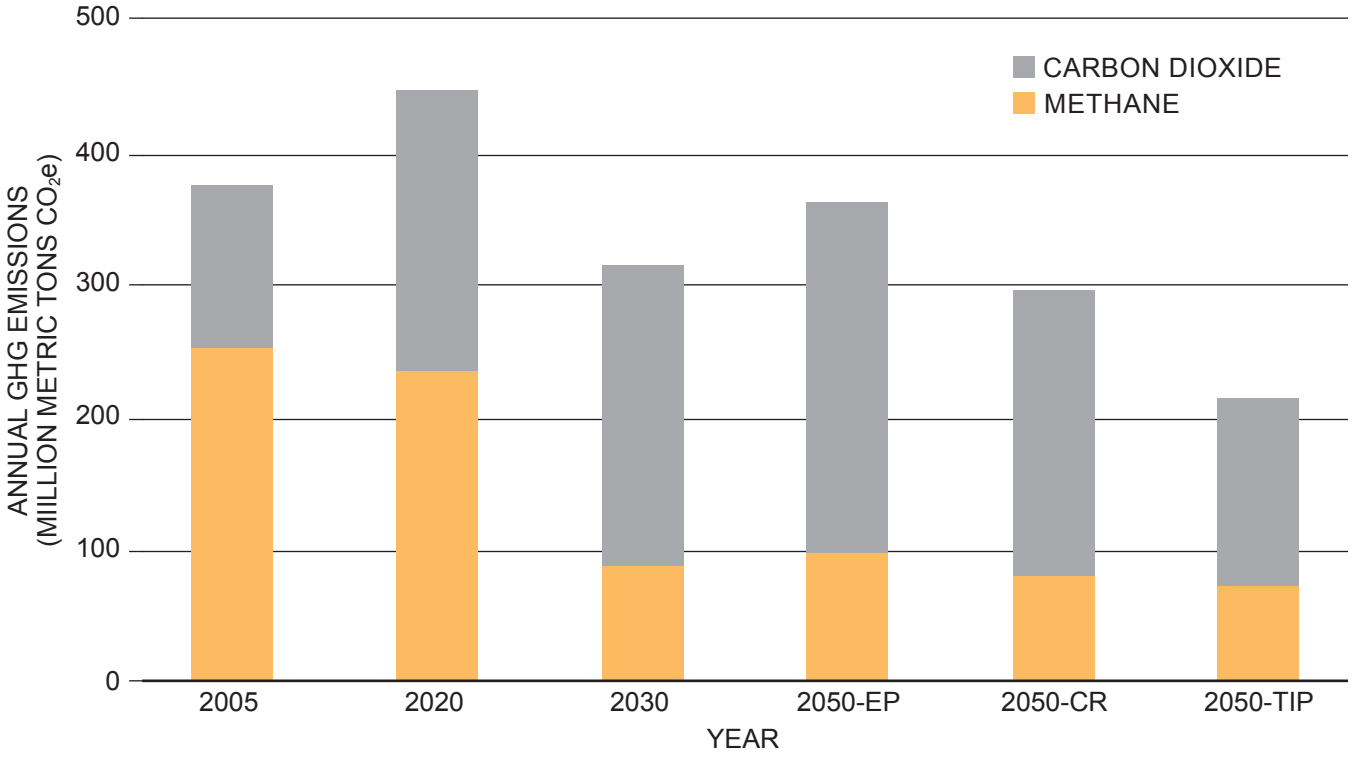


Figure 1-41. *GHG Emissions Pathways in This Study, Based on EPA 100-Year GWP Factors*

positioned to develop technology and help enable development of these GHG emissions abatement tools. Modeling the scale and potential of negative emissions technologies warrants its own scientific analyses and is outside the scope of examining the potential for direct emissions reductions from natural gas supply chains.

This section primarily discusses absolute emissions reductions for consistency with U.S. GHG emissions reduction goals, which are on an absolute basis. Societal reductions in GHG emissions intensity are also important. Chapter 4 includes the application of these same emissions pathways to a simplified life cycle model for the methane and overall GHG intensity of the U.S. natural gas supply chain.

FINDING 52: The Existing Policies Pathway for this study estimates that reductions associated with the suite of federal regulations will reduce methane emissions from sources in the U.S. Greenhouse Gas Inventory by 63% by 2030 and contribute approximately two-thirds of the reductions needed for the United States to contribute a 30% reduction to the Global Methane Pledge.

FINDING 53: The Existing Policies Pathway for this study estimates that emissions reductions within the scope of this study could contribute ~2% (4% relative) of the 50%–52% reduction in economy-wide net GHG emissions by 2030, relative to a 2005 baseline, as part of the Paris Agreement's Nationally Determined Contribution for the United States.

FINDING 54: While methane emissions are expected to reduce by 2030, carbon dioxide emissions will increase through 2050 on the Existing Policies Pathway. The Technology, Innovation, and Policy Pathway estimates methane emissions reduction of more than 70% and carbon dioxide reduction of more than 25% by 2050, which would represent

~3% of baseline 2005 national net GHG emissions.

G. Additional Voluntary Reduction Efforts

Estimating 2030 and 2050 sector-wide emissions in a dynamic technology and policy development environment has large and inherent uncertainties. For a simple summary, the 2020 baseline emissions from the GHGI can be grouped as methane emissions and flaring (60%) and energy use (40%), which is primarily carbon dioxide emissions.

For methane and flaring emissions, as discussed in-depth in this chapter, there has been significant resources devoted through industry voluntary efforts, such as the Environmental Partnership, and multistakeholder efforts, like the Natural Gas STAR Program, to understand abatement options, share case studies, and develop industry best practices. The suite of federal methane regulations that have also been discussed in this chapter are in the process of codifying many of these best practices, as well as additional requirements for emissions reductions across the natural gas supply chain. As a result of these regulatory developments, there are limited additional source abatement levers discussed in this chapter, with the exception of work, including by the DOE ARPA-E REMEDY program, on reducing methane slip from lean-burn reciprocating compressor engines. In recommending additional emissions reduction levers, the study wanted options to be clearly accretive to the suite of proposed federal regulations, versus simply recommending reductions that have been proposed in regulation, which could potentially lead to double counting of emissions reductions within pathways.

This is an ambitious methane emissions and flaring reduction path in the U.S. natural gas supply chain over the next five years. While the regulatory development process is, for some stakeholders, an end point in terms of work, regulations are the start of a compliance process within the regulated community. Infrastructure to support flaring reductions, control technologies to reduce methane venting, methane measurement requirements, and additional LDAR programs for the oil and gas industry are expected to require significant, multibillion-dollar investments across companies in the industry and dedicated resourcing within companies to execute. At the same time that regulations are expected to require significant reductions in inventoried methane and flaring sources, there is also the challenge to develop and implement measurement-informed methane emissions inventory frameworks, which is discussed in-depth in Chapter 3.

With the reduction of methane emissions and flaring, GHG emissions associated with fuel combustion for energy use for essential drilling, heat, and compression activities throughout the natural gas supply chain are modeled to grow as a percentage of overall emissions in the sector, as shown in Figure 1-41, which shows a higher percentage of carbon dioxide emissions, compared to methane emissions, in the sector in 2030 and 2050 pathways. There are undoubtedly companies working to reduce these GHG emissions as part of voluntary GHG emissions reduction programs and energy efficiency improvement initiatives. However, compared to methane emissions sources and flaring, there has been less work to systemically analyze industry-wide reduction opportunities.

Understanding additional GHG emissions reduction opportunities and executing cost-effective voluntary GHG emissions reduction projects is expected to be a part of company business planning throughout the natural gas supply chain. At the company level, this will require staff and monetary resources to analyze abatement opportunities to a point that investment decisions can be made and execute projects to reduce emissions.

RECOMMENDATION 18: *The NPC recommends that companies throughout the natural gas supply chain dedicate additional resources to analyzing further GHG emissions reduction opportunities and execute projects that they consider to be cost effective.*

V. CONCLUSION

Abundant, affordable natural gas is the largest source of primary energy production in the

United States. It will continue to play a crucial role in energy security and an important role in economic security beyond 2050 under all EIA scenarios noting the EIA does not currently provide a net-zero-by-2050 scenario as EIA only recognizes existing policies and regulations. In 2022, natural gas provided significant percentages of primary energy use in the electric power, industrial, residential, and commercial sectors. In the last two decades, natural gas consumption has increased by more than 55%, primarily driven by new unconventional shale resource development. Through jobs and the energy supplied, the natural gas and oil industry supported $1.8 trillion of U.S. GDP, about $5,500 per person, and 7.6% of the national total. The United States is now the world's leading exporter of LNG, which was a key contributor to European energy security as Russia gas deliveries decreased in 2022.

The natural gas supply chain is also a source of GHG emissions, representing approximately 33% of U.S. methane emissions and 5% of U.S. carbon dioxide emissions. The U.S. natural gas sector is expected to contribute to U.S. GHG emissions reduction goals, both through historic displacement of higher-emitting coal assets in the power generation sector, and through future reductions in the natural gas supply chain emissions. Prior to the extension of existing federal methane regulations that began around 2022, GHG emissions reduction efforts had been ongoing in the sector through voluntary efforts and state regulatory programs, on which many of the federal methane regulations draw for experience. Given the complexity of the U.S. natural gas supply chain, durable policy designs will need to recognize the need to reduce emissions across operators of all sizes, current emissions profiles, and organizational capabilities.

For methane emissions, this study developed a 2030 estimate of emissions based on the suite of emerging federal methane emissions regulations. Based on literature reviews for this study, such a combined estimate had not been made to date. The EP pathway for this study estimates more than a 60% reduction in methane emissions from the sector by 2030, which would equate to approximately a 20% reduction in overall national methane emissions on the same timelines as the Global Methane Pledge. Billions of dollars in investments will be needed by the natural gas sector to implement these regulations.

For carbon dioxide emissions, the near-term reduction pathway is less clear. Existing policy estimates by EIA for the sector indicate flat to increasing carbon dioxide emissions from the sector due to growth in overall production volumes and LNG export capacity. This is analogous to the overall global challenge to reduce GHG emissions while ensuring energy security and energy equity. This study identifies specific technology needs for further research, development, and deployment to reduce carbon dioxide emissions in the natural gas supply chain and the need for market mechanisms to help with reducing the residual emissions in the sector. The range of 2050 emissions pathways examined in this study would represent reductions of 1%–3% relative to 2005 U.S. net emissions.

CASE STUDY: EMISSIONS MANAGEMENT IN ALASKA NORTH SLOPE

ConocoPhillips operates the Kuparuk Oil Field (Kuparuk) located on the Alaska North Slope (ANS) approximately 300 miles north of the Arctic Circle. Production in Kuparuk began in 1981, and Kuparuk is one of the largest conventional onshore producing fields in the United States with more than 500 active producing wells (Figure 1-42).[1]

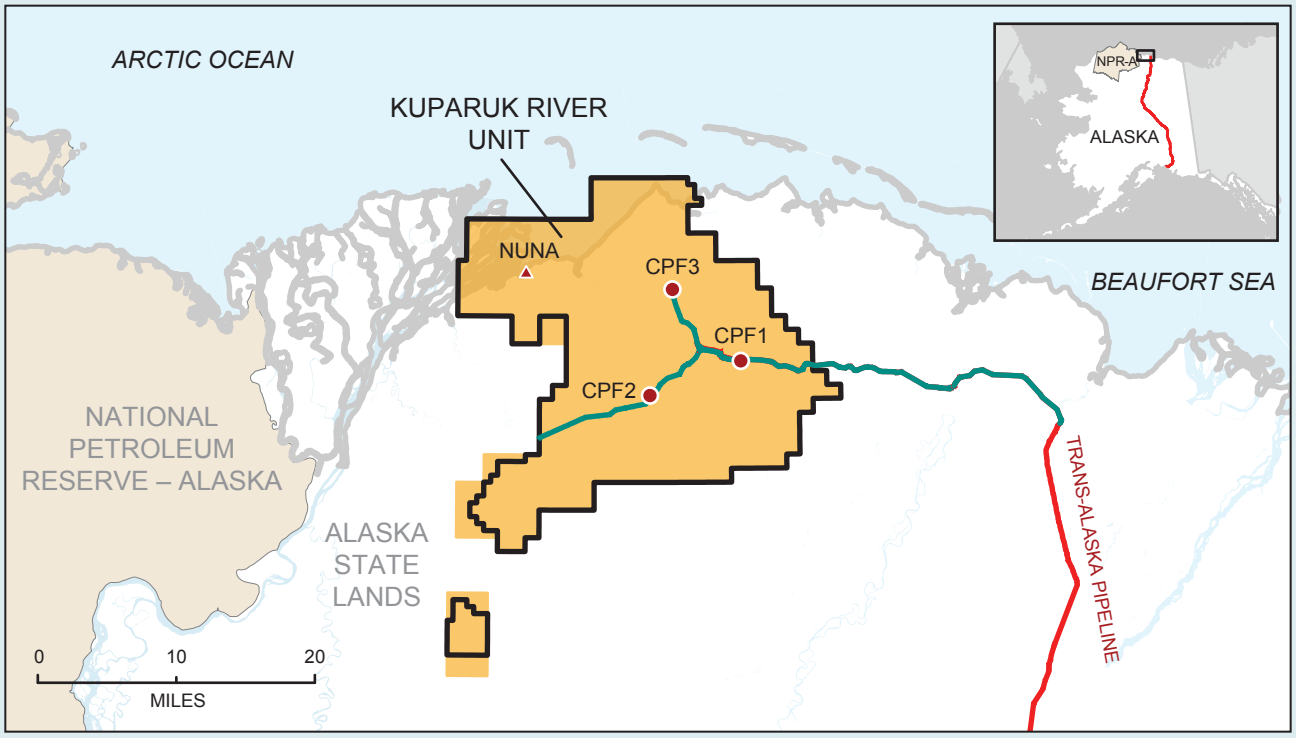
Operating in the Arctic necessitates design and operational standards and protocols that are unique to the location and differ from those applied elsewhere in the United States.

The physical climate of the ANS is harsh, marked by persistently low wintertime temperatures, consistent winds, and a sun that remains below the horizon for nearly two full months per year. ANS-specific weather data show that the average daily temperature is below 0°F for approximately five months out of the year. Snow is typically on the ground from about September to June each year.[2] Winds greater than 10 miles per hour occur more than 40% of the year causing periods of blowing snow and reduced visibility. The harsh physical and climate conditions on the ANS necessitate fit-for-purpose engineering designs. One of the primary design features is that most process equipment is located inside buildings to shelter equipment and personnel from the weather. Due to this enclosed design, gas leaks cannot be tolerated for personnel and process safety reasons, thus buildings typically contain gas detection equipment that alerts operators to leaks so they may be expeditiously repaired.

Subsurface mineral rights in Alaska are mostly held by one of three entities: the state of Alaska, the federal government, and Alaska Native corporations formed under the Alaska Native Claims Settlement Act of 1971. All oil and gas operations, when public or private, are

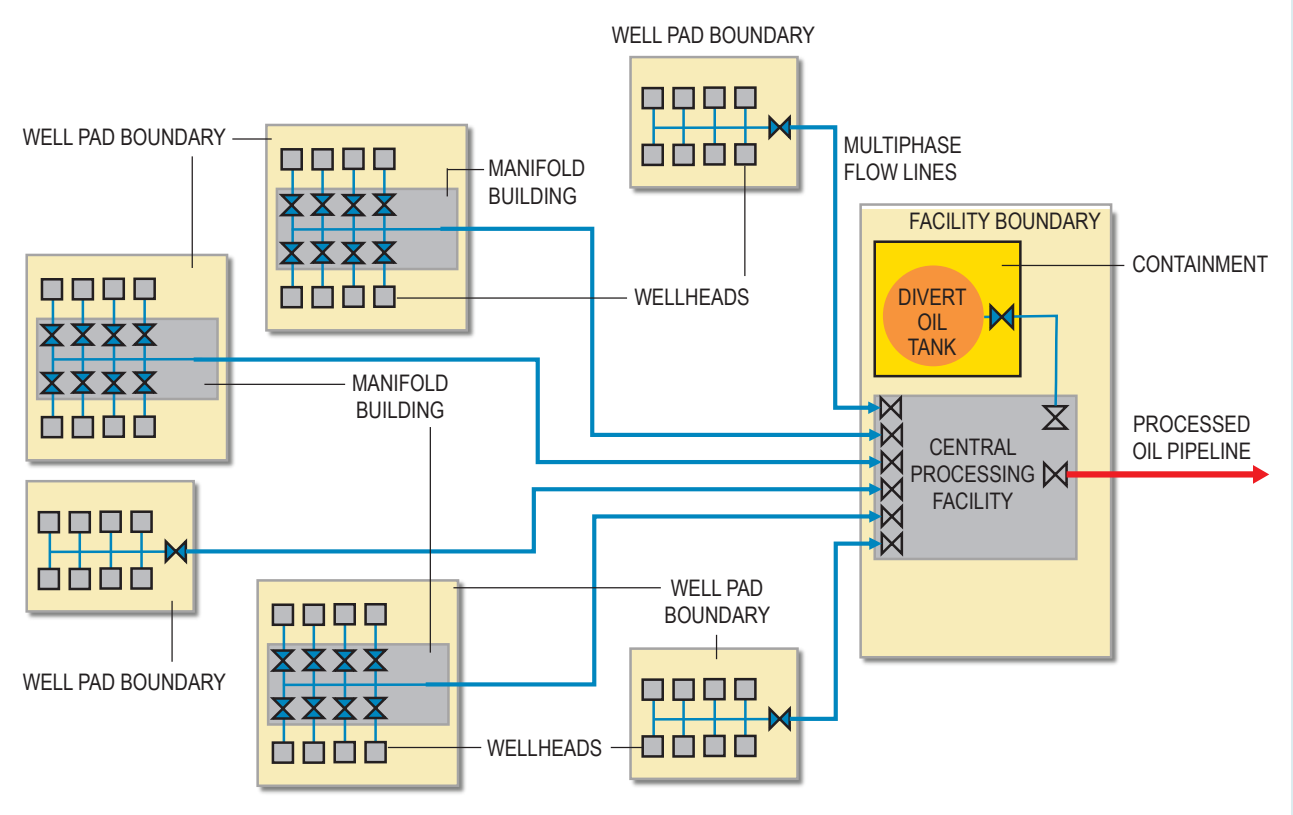
1 ConocoPhillips Alaska. "Kuparuk." n.d. https://alaska.conocophillips.com/who-we-are/alaska-operations/kuparuk/.

2 Shulski, Martha and G. Wendler. 2007. "The Climate of Alaska." The University of Alaska Press. ISBN 1602230072. https://www.researchgate.net/publication/285458181_The_Climate_of_Alaska.



Source: ConocoPhillips.

Figure 1-42. *Location of the Kuparuk Oil Field*



Source: ConocoPhillips, 2023.

Figure 1-43. *Simplified Diagram of a Kuparuk Oil Production Facility*

subject to regulations by the Alaska Oil and Gas Conservation Commission (AOGCC), which regulates and "oversees oil and gas drilling, development and production, reservoir depletion and metering operations on all lands subject to the state's police powers."[3] One of the AOGCC mandates is to prevent waste of Alaska oil and gas resources, and it is believed to have one of the strictest rules against flaring among any of the state conservation commissions. The AOGCC has specific regulations limiting the volume and/or time an operator may flare or vent gas to the atmosphere, after which the operator may be subject to repayment of lost royalties, fines, or penalties.[4] The AOGCC regulations drive Alaska operators to manage their gas in a way that significantly limits both venting and flaring.

Most of Kuparuk's gas handling strategies and designs can be linked back to Arctic weather conditions or AOGCC regulations.

Figure 1-43 is a conceptual overview of ANS production operations. There are mul-tiple drill sites, each housing multiple production wells, which are connected via multiphase pipelines (containing oil, water, and gas) to a central processing facility. Separation of the produced fluids occurs at the central processing facility, not at the drill site.

A drill site (of which six are depicted in Figure 1-43), consists of the wellheads (anywhere from 10 to more than 70 per drill site), which are enclosed in small well houses; manifold buildings (where each individual well's production is commingled into a common pipe flowing from the gravel pad toward the processing facility); occasionally a production heater to prevent produced water from freezing; metering; and tanks that store materials that are not

3 Alaska Oil and Gas Conservation Commission. n.d. https:/www.commerce.alaska.gov/web/aogcc/AboutUs.aspx.

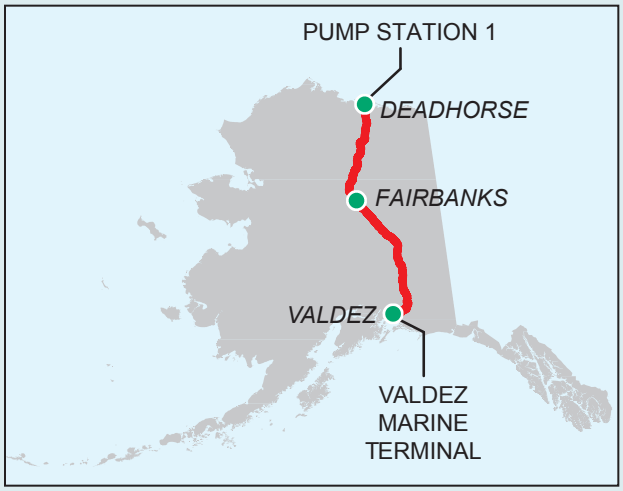
4 Alaska Admin Code. "20 AAC 23.235 – Gas disposition." n.d. https://www.akleg.gov/basis/aac.asp#20.25.235.

produced fluids (e.g., methanol for well "freeze protect").[5] Except when wells are being completed or having maintenance performed on them, there is no active fluid separation at the drill sites. During normal production operations, all fluid separation occurs at the processing facilities.

The processing facilities receive all produced fluids from the drill sites, separate them into their water, gas, and oil phases, and route gas and water back to the drill sites for injection into the reservoirs, using some of the gas as fuel for the facility equipment. The processing facilities are fully staffed around the clock, are almost entirely enclosed, and consist of separators; equipment necessary to route fluids to their destination, such as pumps and compressors; and power generation equipment. The processing facilities export only sales-quality crude oil, are remote from public infrastructure, and must be self-contained and self-sustaining.

At the centralized processing facilities, produced sales-quality crude oil is not stored as one might find in the tank batteries common in the Lower 48 states. The produced sales-quality oil is piped directly from the processing facility to Pump Station 1, the beginning of the Trans-Alaska Pipeline System (TAPS), where the oil is piped to Valdez, Alaska (Figure 1-44) for shipment to the U.S. West Coast and beyond. There are large divert oil tanks (approximately 55,000 bbl each) at some facilities. These divert tanks are used for emergency situations (e.g., when a pump station unexpectedly shuts down and cannot accept oil). During such a time, the produced oil will accumulate in these tanks to act as a wide spot in the line, and they will be emptied back into the pipeline when normal operations resume. These process tanks are equipped with vapor recovery systems.

Notably, gas is not exported from the ANS. TAPS only carries sales-quality crude oil, so



Source: ConocoPhillips, 2023.

Figure 1-44. *Trans-Alaska Pipeline System–Pipeline Carrying Sales Crude Oil from the ANS to Valdez*

there is no mechanism to market ANS gas. This fact necessitates special gas handling uses and protocols. The associated gas that comes to surface is used in one of three ways: 1) on-site fuel source, 2) wellhead artificial lift, or 3) reinjection into the producing reservoir for enhanced oil recovery. These three uses for the associated gas ensure that gas is not wasted by either venting or flaring. While there are a few instances of local gas sales, they are very small in comparison to the three prevailing uses of Kuparuk gas.

At Kuparuk, flaring as a means of gas disposition only occurs during process upsets or equipment malfunctions. Otherwise, flaring is limited to small flares for the purpose of purging oxygen and maintaining a pilot flame. The safety flares are located at each centralized processing facility and are used in the event of rapid equipment depressurization. Since the processing facilities are handling large volumes of associated gas, flares are a crucial safety device for workers and infrastructure. Kuparuk does not conduct routine flaring.[6] When flaring does occur in connection with a process upset, operators immediately take action to mitigate process

5 For wells that are not actively producing, methanol is a material that is injected inside the wellbore to keep the downhole fluids from coming into the permafrost zone (where produced water could freeze inside the pipe). This is referred to as "freeze protect."

6 The World Bank. "Zero Routine Flaring by 2030 Reporting." "ZRF FAQ." n.d. https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/qna#8.

conditions and stop the flaring. Such actions include shutting in wells to suspend production. Flares are not used as a method to increase gas handling to facilitate production.

Kuparuk does not use natural gas-driven pneumatic devices. Pneumatic devices are utilized but are driven by instrument air. Given that most process equipment is located indoors, gas leaks and venting cannot be tolerated for safety concerns. Therefore, Kuparuk was designed to operate instrument air-driven pneumatic devices since its original design and construction in the 1980s.

To further reduce the need for natural gas-burning equipment, waste heat recovery from power generation turbines is utilized for building heat. Operating in the Arctic necessitates heat for utility purposes. On-site gas-fired turbines are used to generate power (since there is no public electric grid available) and waste heat is recovered from that process to heat buildings, including offices and worker housing. Kuparuk does have natural gas-driven building heaters installed, but they are only used as a backup. Using waste heat allows Kuparuk to minimize additional fuel-driven heaters, therefore reducing emissions.

Kuparuk utilizes a gas capture system on wet seal centrifugal compressors. The large volume of associated gas used for wellhead artificial lift and reservoir gas reinjection must be compressed up to very high pressures. Kuparuk uses large (15,000+ hp) centrifugal compressors to accomplish these tasks. It is not common to find this size of compressor in upstream operations, but since gas is not exported, this is necessary at Kuparuk. Wet seal centrifugal compressors circulate lube oil under high pressure between rings around the compressor shaft, forming a barrier against the compressed gas to prevent its escape to the atmosphere. The lube oil creates a "wet seal" barrier between the rings. Due to the pressure of the gas within the compressor shaft, some gas becomes entrained within the lube oil while it is circulated between the rings. The entrained gas must be extracted from the lube oil so that the oil can be recirculated between the rings to effectively maintain the wet seal barrier. Extracting the gas is a process called wet seal degassing. Wet seal degassing processes are generally unmitigated, venting all degassed emissions to the atmosphere. However, Kuparuk was originally designed to capture most of the gas from the degassed lube oil, which ultimately results in vent rates analogous to dry seal compressors (a superior design with very low vent rates).[7]

Process tanks have vapor recovery systems to capture gas and reroute to process. As briefly discussed earlier, there is no routine storage of oil onsite (no storage tanks), as produced oil continuously flows from the ANS wellhead to the Valdez Marine Terminal, approximately 800 miles downstream. Though there are no atmospheric storage tanks, there are various pressurized process tanks, which contain accumulations of oil. These process tanks are equipped with vapor recovery systems so that gas is not vented to the atmosphere during normal operations.

Though the Kuparuk Oil Field is more than 40 years old, it was originally designed to minimize gas venting and waste because of its physical location in an Arctic environment and the regulatory requirements imposed by the state of Alaska. Kuparuk has been able to maintain good methane management practices through its design and continued operations by employing gas reinjection, no routine flaring, instrument air-driven pneumatics, waste heat recovery, wet seal compressor gas capture systems, and tank vapor recovery.

7 Kuparuk's compressors utilize the same capture design as those studied by the EPA Natural Gas Star program: Centrifugal Compressor Wet Seals Seal Oil Degassing and Control, April 2012. https://www.epa.gov/sites/default/files/2016-04/documents/smith.pdf.

Chapter 2

SOCIETAL CONSIDERATIONS AND IMPACTS

OVERVIEW

The focus of this chapter is to provide insights on the Societal Considerations and Impacts (SCI) of reducing greenhouse gas (GHG) emissions along the U.S. natural gas supply chain (NGSC). It examines how—while developing and implementing GHG emissions reduction projects, activities, and policies—to avoid or mitigate adverse impacts on communities, particularly the disadvantaged, while maximizing the effectiveness of community benefits that can flow from these actions.

To this end, this chapter provides a background section of SCI issues, including a section on community and environmental justice (EJ) considerations. The EJ section begins to illuminate why such issues should be addressed in a GHG emissions reduction study or considered when undertaking GHG emissions reduction activities. The SCI task group also considered the SCI implications of recommended policies, practices, and technologies presented in both this chapter and in observations and recommendations throughout the study. This chapter also begins to identify and analyze the trade-offs from SCI and EJ perspectives that policymakers, regulators, and project developers may consider throughout their decision-making processes.

The SCI task group learned that some companies in the NGSC are already practicing community engagement; several case studies are included in this chapter and a compendium of best practices is included in Appendix C. However, the task group was informed through surveys and focus groups that there is no one-size-fits-all method for meaningful engagement with local communities, whose concerns and needs can only be understood by preparing, listening to the community, learning, and collaborative actions.

In addition to the SCI chapter, the SCI task group evaluated the recommendations and analyses throughout this report through an SCI lens. These recommendations and actions should broadly consider the following:

- Implementing GHG emissions reduction actions along the supply chain, providing societal benefits inclusive of environment, health, and economic impacts
- Transforming frontline community and stakeholder engagement planning, practices, and two-way communication
- Enabling workforce development and labor engagement

Efforts across the United States have emphasized identifying best practices in community engagement and how best to develop community benefit programs. This chapter explores what robust and meaningful community engagement could look like, leveraging case study examples of how engagement, benefit sharing, and impacts mitigation is currently being managed across the NGSC.

I. INTRODUCTION

A. Joint *Harnessing Hydrogen* and *Charting the Course* Content: Societal Considerations and Impacts Analysis

The National Petroleum Council (NPC) will deliver two studies to the Secretary of Energy:

Charting the Course: Reducing GHG Emissions from the U.S. Natural Gas Supply Chain, and *Harnessing Hydrogen: A Key Element of the U.S. Energy Future*. These studies provide, for the first time in an NPC study, a dedicated, stand-alone SCI discussion to evaluate and integrate community and societal considerations into the study analyses, findings, and recommendations—commensurate with evolving trends in civil society. A portion of the SCI scope of work for both studies was accomplished by a joint study working group composed of select members from both studies' SCI task groups. The outcome of this joint effort are sections: (1) a historical overview of current community impacts and justice-linked issues, particularly those relating to the energy sector; (2) an understanding of some of the current benefits, cobenefits, and trade-offs that communities experience, and relevant Justice40[1] principles; and (3) an analysis of best practices in the community engagement process. In addition, findings and recommendations shared by both SCI chapters are labeled "joint" throughout the chapter. While this content was developed by the joint SCI working group, it was adapted to each study's scope and sector of the energy industry—the joint content is not duplicated exactly across both studies.

B. Scope

In her letter of April 22, 2022, Secretary of Energy Jennifer Granholm included a specific request for the NPC to discuss "potential trade-offs of low- and no-emissions natural gas, including energy and economic security, EJ, the carbon intensity of the products resulting from its use, e.g., heat, power, and chemicals, and other environmental impacts" (see Appendix A). The resulting analysis in this chapter explores the complex intersection between EJ, community engagement, and the benefits and impacts of reducing GHG emissions across the NGSC. The chapter should be considered an initial step in a robust and critically needed undertaking to better understand these dynamics.

Any incremental energy infrastructure that must be built to enable GHG emissions reductions may have impacts on communities. Thus, this chapter seeks to illuminate how understanding the NGSC SCI context could inform how this new infrastructure might impact communities or the environment, as well as some of the steps that can be taken to engage communities effectively while ensuring disadvantaged communities[2, 3] are not disproportionately burdened. While the chapter avoids identifying, quantifying, or characterizing the overall social value and community impacts of natural gas itself as an energy source as much as possible, isolating emissions reduction activities from natural gas itself was often difficult to achieve in the SCI analysis.

ENVIRONMENTAL JUSTICE

The Secretary's letter asked the NPC to discuss "environmental justice." The Secretary did not provide a definition of the term, however both NPC studies have referenced some more widely used definitions of EJ and associated terminology which are utilized by the government agencies and others. These definitions are not representative of the entire compendium of definitions or views on these issues. The Societal Considerations and Impacts title for both study sections was chosen based on guidance and engagements with the Department of Energy (DOE) as an appropriate descriptor for a wide range of external community and environmental concerns across the United States. Other terminology used by EJ researchers and advocates with definitions of some of those terms can be found in Appendix C.

The study achieved limited, although critical, participation from community and EJ groups. To help address this gap, the study commissioned focus group field work in six locations across the U.S.—relevant to the NGSC—to deepen

1 DOE. "Justice40 Initiative." 2020. Energy.gov. https://www.energy.gov/justice/justice40-initiative.

2 CEQ. "Climate and Economic Justice Screening Tool: Frequently Asked Questions Q: How Does the Tool Identify and Define Disadvantaged Communities?" 2022. https://www.whitehouse.gov/wp-content/uploads/2022/02/CEQ-CEJST-QandA.pdf.

3 Executive Office of the President, Office of Management and Budget. "Memorandum for the Heads of Departments and Agencies re. Interim Implementation Guidance for the Justice40 Initiative." July 20, 2021. https://www.whitehouse.gov/wp-content/uploads/2021/07/M-21-28.pdf.

understanding of what place-based community concerns are, what good engagement looks like to them, and what trade-offs they are aware of and willing to accept in support of reducing natural gas GHG emissions. Using messages and themes that emerged from the focus group process, a poll of the six regions was deployed to test the validity and prevalence of community concerns in the same regions. Through the focus group process, the SCI task group learned that there is no one-size-fits-all method for meaningful engagement with local communities.

Without more direct input from community and EJ groups, the SCI contribution to this study represents the generalized observations of the chapter authors. It is based on examples from adjacent sectors, peer-reviewed literature, and this primary research. Given time and resource constraints, this study could not encapsulate the myriad perspectives around energy project development, but instead offers high-level observations useful to integrating robust community engagement and EJ principles in the project development process.

JOINT FINDING 1: **The Societal Considerations and Impacts sections of the Harnessing Hydrogen and Charting the Course studies provide an overview of potential social, environmental, and economic impacts associated with energy development. These two study sections, with their respective findings and recommendations, are provided as an overview to help inform the broader interests and practices related to energy development and the energy transition, including energy and environmental justice and community engagement, but do not represent any individual community perspective or comment on the topics covered.**

JOINT RECOMMENDATION 1: ***The NPC recommends that the DOE undertake a stand-alone, comprehensive societal considerations and impacts study, related to energy development, including but not limited to, low carbon intensity hydrogen development and GHG emissions reduction supply chains as well as other facets of energy development. It is recommended that this study be conducted with the National Academy of Sciences, Engineering, and Medicine's Division of Behavioral and Social Sciences and Education and the Board on Energy and Environmental Systems, with coordinated input and concerted effort from the NPC and other stakeholders.***

C. Joint Content in *Harnessing Hydrogen* and *Charting the Course*: Alternative Views of GHG Emissions Reductions in the Natural Gas Supply Chain

Efforts to reduce GHG emissions from the NGSC is an increasingly important form of GHG mitigation. These activities will likely be connected to traditional energy infrastructure and development needed to meet overall GHG emissions reduction goals, including methane reduction goals as set forth in the Secretary's study request letter. While reducing GHG emissions is a societal benefit writ large, care must be taken when implementing projects and activities, especially near existing communities.

It is important to acknowledge that many individuals and organizations, however, want the U.S., and the world, to significantly reduce the use of fossil energy in a few years as a major means of addressing climate change. A number of environmental and EJ groups, researchers, journalists, and interested commentators regularly cite the Intergovernmental Panel on Climate Change (IPCC) 2023 report, which warns "[p]rojected CO_2 emissions from existing fossil fuel infrastructure without additional abatement would exceed the remaining carbon budget for 1.5°C"[4] and that global warming this century is on course to exceed an agreed 1.5°C limit without drastic and immediate cuts in GHG emissions, including "the phasing out of fossil fuels."[5]

4 IPCC. 2023. "Climate Change 2023: Synthesis Report. Contribution of Working Groups I, II, and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, H. Lee and J. Romero (eds.)]. IPCC, Geneva, Switzerland. doi:10.59327/IPCC/AR6-9789291691647.

5 IPCC. 2023. "Climate Change 2023: Synthesis Report. Contribution of Working Groups I, II, and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change: Summary for Policymakers Headline Statements." https://www.ipcc.ch/report/ar6/syr/resources/spm-headline-statements/.

In its *Justice40 Initiative Implementation Phase 1* Recommendations, the White House Environmental Justice Advisory Council states that "federal investments in fossil fuel infrastructure promote serious harm to disadvantaged communities while locking our country and the world into worsening climate change" and that "[s]uch investments divert limited federal resources from generative, clean energy initiatives advanced by Justice40."[6] For example, the International Energy Agency (IEA) May 2021 report states that reducing global carbon emissions to achieve net zero emissions by 2050 will require "nothing less than a complete transformation of how we produce, transport, and consume energy."[7] The report also states that achieving the transformation will require a managed decline in the use of fossil fuels, leading the IEA to assert that there is "no need for investment in new fossil fuel supply" beyond those already committed to by 2021 and calls for "phasing out all unabated coal and oil power plants by 2040."[8] Similarly, the Group of Seven this year called for a "global effort to accelerate the phase-out of unabated fossil fuels to achieve net zero in energy systems by 2050."[9]

As projections from IEA, EIA and others indicate, however, such change must accommodate the practical constraints of both rising energy demand globally and the relatively gradual or incremental pace of accomplishing the energy system transition to nonfossil energy-based systems.[10] In the meantime, the NPC has been recommending,[11] and a meaningful portion of the oil and gas industry has been seeking to achieve, reductions in GHG emissions and development of technologies to achieve such GHG reductions.

II. ENVIRONMENTAL JUSTICE

There are instances where active EJ conversations have arisen around existing or historic energy sector developments. Some GHG emissions reduction activities may be colocated with existing oil and gas development and should consider the EJ context of that region and the communities therein. It is challenging to discuss the SCI implications of GHG emissions reduction activities of the NGSC in isolation. Community perceptions of these new activities may be impacted by the SCI and historical context of oil and gas activities.

Many communities play a pivotal role in future energy development, including GHG emissions reduction projects from the NGSC. EJ advocacy specifically aims to ensure that burdens (e.g., energy burden, environmental burden, climate change burden, infrastructure burden) from GHG emissions reduction activities do not unduly impact disadvantaged communities. EJ advocacy seeks to secure equal environmental protection under the law for disadvantaged communities as well as resources to help them in their engagement about critical decisions affecting where they live and work, mitigate impacts, and secure benefits.

A. Joint *Harnessing Hydrogen* and *Charting the Course* Section

1. Background

There are several concepts and definitions in social equity/inequity and EJ that are relevant to the evolving way that industries engage with communities. These definitions are fundamental to understanding communities with EJ considerations, organizations, industry, and policymakers.[12]

The development and operation of energy infrastructure, including activities that reduce GHG emissions from the NGSC, has potential

6 White House Environmental Justice Advisory Council, Justice40 Initiative Implementation; Phase 1 Recommendations. August 18, 2022. https://www.epa.gov/system/files/documents/2022-08/WHEJAC%20J40%20Implementation%20Recommendations%20Final%20Aug2022b.pdf.

7 IEA. 2021. "Net Zero by 2050–Analysis." https://www.iea.org/reports/net-zero-by-2050.

8 Birol, Fatih. "Peak Fossil Fuel Demand Will Happen This Decade." *The Financial Times*. September 11, 2023. https://www.ft.com/content/f6155d7b-2ef7-4f62-a08a-b640b7e87fca.

9 The Economic Times. "COP28 Climate Dispute: What Are 'Unabated' Fossil Fuels?" November 8, 2023. https://economictimes.indiatimes.com/news/international/world-news/cop28-climate-dispute-what-are-unabated-fossil-fuels/articleshow/105066880.cms?from=mdr.

10 IRENA. 2023. "World Energy Transitions Outlook 2023." International Renewable Energy Agency. Abu Dhabi. https://www.irena.org/Digital-Report/World-Energy-Transitions-Outlook-2023#:~:text=This%20first%20volume%20of%20the.

11 National Petroleum Council. "Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage." 2019. https://dualchallenge.npc.org/.

12 Please see Appendix C for definitions of environmental justice.

environmental and societal impacts. Communities proximal to energy development report both positive and negative impacts on community and individual well-being. It is important to minimize adverse impacts, especially on disadvantaged communities, while also maximizing the effectiveness of community benefits that can flow from nearby economic development.

The DOE is engaging in efforts to find incentives and develop approaches that will promote true and robust community participation with energy development and its benefits, without inhibiting investments in such development by the private sector.

Throughout this subchapter, the term disadvantaged communities (DACs)[13] is used to refer to the working definition currently in use by the DOE to reflect cumulative burdens and includes data for indicators collected at the census-tract level. These burden indicators are grouped across four categories: fossil dependence, energy burden, environmental and climate hazards, and socioeconomic vulnerabilities. These are discussed in greater detail in the following section. The Climate and Economic Justice Screening Tool (CEJST) that the Council of Environmental Quality has developed also balances all communities and includes eight categories of disadvantaged status indices "related to underinvestment in energy, transit, workforce development, housing, water infrastructure, and more."[14]

2. Evolution of Today's Community and Justice Issues

a. History of Environmental Justice

While EJ has come to the forefront of U.S. public dialogue in recent years—driven in part by the prominence of federal programming related to EJ considerations under the Biden administration—the issue has an important and substantial history. This deep history shapes how people and organizations approach and engage with this topic. EJ traces its activist-led movement roots back to the 1960s to 1980s, led by predominantly Black communities that sought to address the inequity and potential for disproportionate harms from environmental hazards due to governmental policies and industrial activities in their communities.

By the 1990s, EJ advocates began developing and advocating for their proposed solutions to the environmental risks faced by DACs. It required, however, expanding the definition of "environment" to be inclusive of fence-line communities.[15] After the Environmental Protection Agency (EPA) Office of Environmental Equity (later renamed Environmental Justice) was formed, a landmark report from their working group marked the first time the U.S. government acknowledged environmental inequality fractures along racial and socioeconomic divides.[16] By 1994, public opinion, and a growing body of scholarly work on the issue, pushed the Clinton administration to act by issuing Executive Order 12898 (EO 12898), encouraging all federal agencies to take EJ under advisement, while also ensuring EJ is achieved as part of their missions.

The EPA definition is referenced by several agencies and external advocacy organizations; this definition broadly institutionalizes community engagement as a base expectation when a decision has direct impacts on their natural or cultural environments, resulting in a policy-based EJ approach.

EPA definition of environmental justice:

"The just treatment and meaningful involvement of all people, regardless of income, race, color, national origin, Tribal affiliation, or disability, in agency decision-making and other federal activities that affect human health and the environment..."

"Fair treatment"[17] means that no group of people should bear a disproportionate burden of

13 It is important to note that some communities do not embrace the term DACs. However, considering the imperfect and evolving lexicon, this study elected to adopt this DOE terminology.

14 Shrestha, R., Neuberger, J., Rajpurohit, S., and Saha, D. 2022. "6 Takeaways from the CEQ Climate and Economic Justice Screening Tool." https://www.wri.org/technical-perspectives/6-takeaways-ceq-climate-and-economic-justice-screening-tool.

15 Bullard, R.D., Mohai, P., Saha, R., and Wright, B. 2007. "Toxic Wastes and Race at Twenty: 1987-2007." https://www.nrdc.org/sites/default/files/toxic-wastes-and-race-at-twenty-1987-2007.pdf.

16 EPA. 1992. "Environmental Equity: Reducing Risk for All Communities." https://rb.gy/flefgn.

17 EPA. "Environmental Justice." February 6, 2019. https://www.epa.gov/environmentaljustice.

environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies. Further, the definition was expanded such that the concept of fair treatment includes not only the consideration of how burdens are distributed across all populations, but also how benefits are distributed.

Meaningful Involvement means that: 1) potentially affected community members have an appropriate opportunity to participate in decisions about a proposed activity that will affect their environment and/or health; 2) the public's contribution can influence the regulatory agency's decision; 3) the concerns of all participants involved will be considered in the decision-making process; and 4) the decision-makers seek out and facilitate the involvement of those potentially affected.[18]

In 2022, EO 14008 was designed to reaffirm federal government consideration of EJ in agency decision-making, just as the nation increased its focus on infrastructure. The order states:

"Agencies shall make achieving environmental justice part of their missions by developing programs, policies, and activities to address the disproportionately high and adverse human health, environmental, climate-related, and other cumulative impacts on disadvantaged communities, as well as the accompanying economic challenges of such impacts."

EJ is intended to recognize and remedy disparate outcomes, among other considerations, caused by discrimination, whether intentional or inadvertent, meaning that there is no one-size-fits-all solution. As such, there is no single, reliable checklist for addressing EJ. Identifying opportunities for addressing environmental injustices requires meaningful engagement with impacted communities; therefore, the design of various policy-based EJ frameworks is to encourage key principles and engender timeliness and thoughtful responses to concerns of EJ.[19] Across all agencies that have formally adopted an EJ program, the themes include: (1) early engagement that allows fair and public deliberation of issues concerning pollution, waste, or hazardous facilities and operations and the potential impacts associated with exposure to processes associated with those facilities; (2) participatory and responsive community engagement related to all stages of project design and operations; (3) mitigation against potential environmental harms that may have a disproportionately impact on DACs; and (4) consideration of historical and current circumstances that may exacerbate inequity and/or consideration and mitigation of the cumulative impacts to DACs.

b. Evolution from Environmental Justice to Energy Justice to Climate Justice to Justice40

JOINT FINDING 2: **The term "environmental justice" or "EJ" has come to mean many different things to different people, including historically a movement for equitable treatment led by Black grassroot leaders. The term EJ is also used to describe specific community concerns related to disproportionate and cumulative negative environmental impacts and burdens. EJ has also been adopted as an academic term and a policy framework.**

In recent years, energy justice has evolved to address inequities such as disproportionate energy cost burdens and environmental or health impacts borne by certain segments of society in utilizing community engagement, organizational capacity building, democracy, and energy community empowerment. "It aims to achieve equality between social, economic, and political participation in the energy system and, ultimately, make the whole system more ethical."[20]

18 EPA. "Learn about Environmental Justice." November 7, 2018. https://www.epa.gov/environmentaljustice/learn-about-environmental-justice.

19 Ramirez-Andreotta, Mónica. 2012. "Environmental Justice: An Overview." https://www.sciencedirect.com/topics/earth-and-planetary-sciences/environmental-justice.

20 University of Sussex. "What Is Energy Justice?" August 24, 2021. https://study-online.sussex.ac.uk/news-and-events/what-is-energy-justice/#:~:text=It%20aims%20to%20achieve%20equality.

"Energy justice refers to the goal of achieving equity in both the social and economic participation in the energy system, while also remediating social, economic, and health burdens on those historically harmed by the energy system ("frontline communities"). Energy justice explicitly centers the concerns of marginalized communities and aims to make energy more accessible, affordable, clean, and democratically managed for all communities."[21]

Commensurate with the development of agency-specific EJ programs designed to improve accountability mechanisms, the U.S. government also created a series of feedback tools that enables public deliberation of EJ issues (e.g., EJ Scorecards, community listening sessions, and Advisory Councils), as well as national-level EJ screening and/or tracker tools (e.g., EJScreen and CEJST).

The absence of a unifying national EJ framework has led to some state-level actions to create laws, regulations, and enforcement mechanisms to address EJ. Likewise, various agencies at the national level have designed bespoke programming to address EJ. There is risk that unharmonized legislation could create contradictions between state and federal efforts.[22] If designed in a complementary manner, state-based EJ efforts can provide missing localized information, legislation, regulation, and enforcement that strengthens EJ considerations in the absence of federal authority or action.

EJ has, and will continue to, evolve as it seeks to secure and enforce environmental protections for vulnerable populations. It is important to recognize that there are different definitions of EJ, differing concerns, and differing ideas of what should be done to address EJ uneasiness. In evaluating environmental injustices, it is important to account for not just contemporary socioeconomic characteristics but also historical contexts and conditions that communities perceived as creating disparate burdens for them. "The practitioner and academic approaches to energy justice emphasize these process-related and distributive justice concerns."[23]

3. Justice40 Principles Overview

The Justice40 initiative directs 40% of the overall benefits of certain federal investments—including investments in clean energy and energy efficiency as well as the remediation and reduction of legacy pollution, among others—to flow to DACs. Many of the DOE's funding programs are covered by Justice40 and have outlined eight policy priorities to guide the DOE's implementation of Justice40:[24, 25]

1. Decrease energy burden in DACs
2. Decrease environmental exposure and burdens for DACs
3. Increase parity in clean energy technology (e.g., solar, storage) access and adoption in DACs
4. Increase access to low-cost capital in DACs
5. Increase clean energy enterprise creation and contracting (Minority Business Enterprises/Disadvantaged Business Enterprises) in DACs
6. Increase clean energy jobs, job pipelines, and job training for individuals from DACs
7. Increase energy resiliency in DACs
8. Increase energy democracy in DACs

The DOE has a working definition of DACs based on cumulative burden and includes data for 36 burden indicators collected at the census-tract level. These burden indicators are grouped across four categories: fossil dependence, energy burden, environmental and climate hazards, and socioeconomic vulnerabilities. Separately, the Federal Office of Management and Budget created

21 Initiative for Energy Justice. "Section 1-Defining Energy Justice: Connections to Environmental Justice, Climate Justice, and the Just Transition." December 23, 2019. https://iejusa.org/section-1-defining-energy-justice/.

22 Perls, Hannah. "EPA Undermines Its Own Environmental Justice Programs-Environmental & Energy Law Program." Harvard Law School. November 12, 2020. https://eelp.law.harvard.edu/2020/11/epa-undermines-its-own-environmental-justice-programs/.

23 Initiative for Energy Justice. 2018. "About the Initiative for Energy Justice." https://iejusa.org/about/.

24 DOE, Office of Energy Justice and Equity. 2020. "Justice40 Initiative." https://www.energy.gov/justice/justice40-initiative.

25 Currently, many planned GHG emissions reduction projects and technologies aren't necessarily included in Justice40-covered programs but may be in the future.

the CEJST for federal agencies to identify DACs by census tract nationwide. Census tracts that meet the thresholds for (1) climate change, (2) energy, (3) health, (4) housing, (5) legacy pollutions, (6) transportation, (7) water and wastewater, and (8) workforce development, in addition to an associated socioeconomic burden, are marked as disadvantaged. In addition, a census tract that is surrounded by DACs, and is at or above the 50th percentile for low income, is also considered disadvantaged.

EJ principles are underpinned by intentional and meaningful involvement with potentially impacted or proximal communities to development activities, including potential GHG emissions reduction projects of the NGSC. The next section of this chapter analyzes community engagement, presents a model based on assessment of best practices, and tests this model through focus groups and associated polls.

III. COMMUNITY ENGAGEMENT

Projects and activities to reduce GHG emissions along the NGSC should involve community engagement best practices to benefit communities and industry. Identifying opportunities to proactively address community concerns requires meaningful engagement with impacted or potentially impacted communities to ensure they can provide their perspectives on projects and better understand the benefits, impacts, and trade-offs of a given project, and support more equitable distribution of community benefits while mitigating disproportionate negative impacts.

FINDING 3: Authentic, ongoing, and robust community engagement activities are critical for building trust between communities and the industry, and to helping ensure GHG emissions reduction projects and activities can proceed.

RECOMMENDATION 2: *The NPC recommends that siting and development of infrastructure to reduce GHG emissions along the natural gas supply chain involve effective community engagement best practices to benefit communities and industry.*

In addition, a common theme among differing perspectives is that local, state, and federal government and industry are called upon to meaningfully engage with historically disadvantaged communities. The roles of government, communities, and industry should be clearly defined prior to engagement. Better understanding the roles that energy developers play versus the responsibilities of government agencies involved in a project may benefit communities.

JOINT FINDING 4: Government and industry have different roles in delivering benefits to communities and the differences are not always clear to members of communities, who are seeking benefits from government programs and/or industry investments. This may result in communities experiencing frustration and dissatisfaction with the community engagement and benefits planning process.

JOINT RECOMMENDATION 3: *The NPC recommends that DOE clarify the roles it and project developers each play in addressing community concerns as early and often as possible in a project development (for developers) or throughout listening sessions and roadshows (for DOE).*

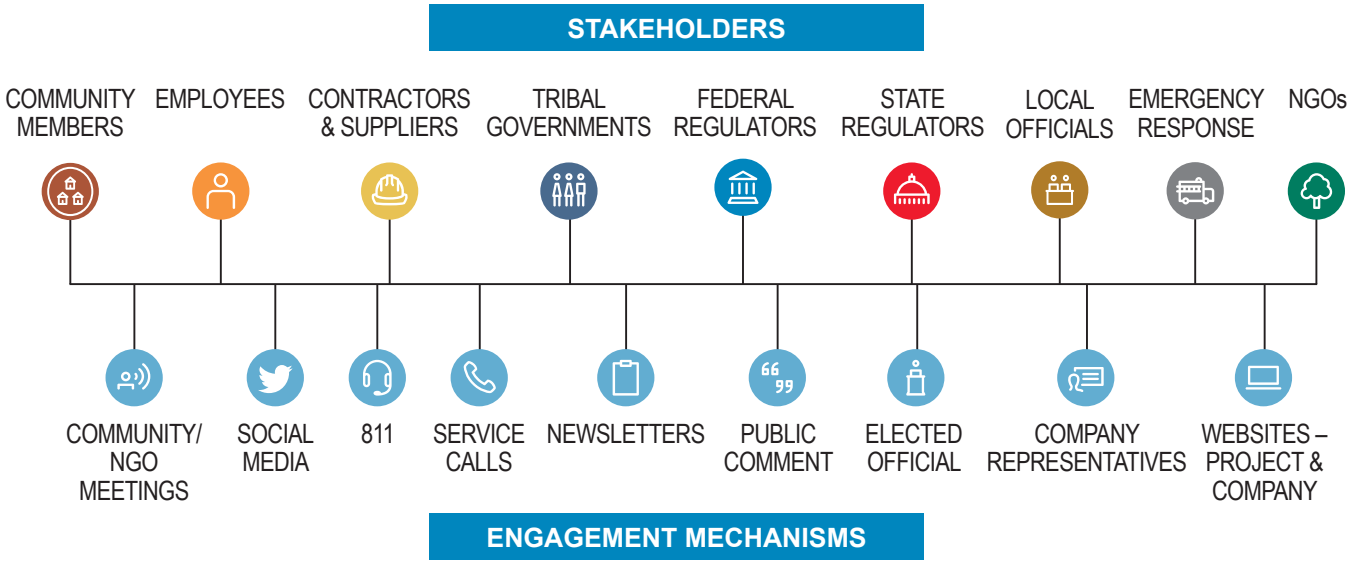
This section describes a framework for community engagement best practices, primary field work conducted for this study to learn select communities' perspectives on this framework, and possible benefits that might accrue to companies that practice robust community engagement activities.

A. Framework for Community Engagement

1. Introduction to Framework for Community Engagement Best Practices

Several core principles define best practices for meaningful community engagement. Importantly, community engagement, when executed well, is part of addressing EJ, but good practices in this area alone should not be assumed as sufficient for the achievement of EJ goals.

Several organizations and entities have developed best practices for successful community



Source: NPC, 2019, "Dynamic Delivery: America's Evolving Oil and Natural Gas Transportation Infrastructure."

Figure 2-1. *Types of Stakeholders*

engagement, informed by decades of experience and input from those most impacted by decisions. For example, IPIECA[26] provides extensive community engagement guidance to the industry in their international operations.

In addition, the 2019 NPC *Dynamic Delivery* study provides a schematic that represents the variety of stakeholders that may be engaged during a project development, as well as a nonexhaustive compilation of available tools. See Figure 2-1 for a summary visual representation.

Another model involving direct collaboration between the U.S. government and impacted communities was launched in 2023. The EPA, in partnership with the DOE, recently launched the Environmental Justice Thriving Communities Technical Assistance Centers Program. These "TCTACs" will receive $177 million to help underserved and overburdened communities across the country. Each of the technical assistance centers will receive at least $10 million to remove barriers and improve accessibility for communities with EJ concerns. With this critical investment, these centers will provide training and other assistance to build capacity for navigating federal grant application systems, writing strong grant proposals, and effectively managing grant funding.[27]

Rather than describe numerous resources and approaches in detail, we draw on them to summarize best practices referencing key resources in this section and Appendix C. Key challenges and shortfalls for community engagement are shared, followed by several recommendations for overcoming them.

The resulting basis for good community engagement can be characterized by an iterative and cyclical Four-step Framework of: (1) Prepare, (2) Listen, (3) Understand/Learn, (4) Collaborate/Respond. This process is conceptualized in Figure 2-2.

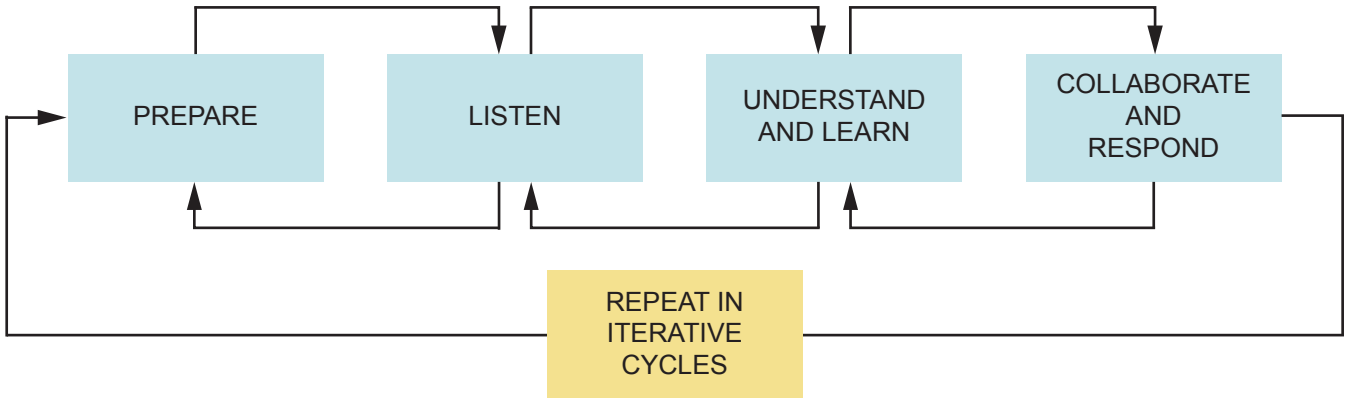
This framework is at the heart of many guidance documents and, for the best community engagement, should be combined with the following five principles:[28]

- Authenticity and trust

26 IPIECA was founded at the request of the U.N. Environment Programme in 1974. It brings together member companies and stakeholders to lead in integrating sustainability by advancing climate action, environmental responsibility, and social performance across oil, gas, and renewables activities.

27 EPA. 2022. "The Environmental Justice Thriving Communities Technical Assistance Centers Program." https://www.epa.gov/environmentaljustice/environmental-justice-thriving-communities-technical-assistance-centers.

28 Developed by the joint *Harnessing Hydrogen-Charting the Course* working group based on research and a review of best practices.



Source: NPC, 2019, "Dynamic Delivery: America's Evolving Oil and Natural Gas Transportation Infrastructure."

Figure 2-2. *Community Engagement Best Practices Model*

- Transparency
- Early, open, responsive, and accessible engagement
- Identify and respond to community and concerns
- Articulation of community value (by developer) and demonstration of value (by the community and government)

When done well, community engagement provides the opportunity to participate meaningfully in a project's design and operation. Utilizing this framework developers, industry groups, government, and communities can work collectively to adopt and continuously improve effective engagement practices that encourage responsible energy development, including the reduction of GHG emissions from the NGSC.

Public or community engagement comes in many forms, and each has its own unique characteristics and goals. Understanding the different types of activities and how they relate to motivations of various stakeholders can be beneficial to project input/planning, though there are no guarantees that any engagement approach will result in a successful project deployment or positive public sentiment.

Community or stakeholder engagement prior to permitting or siting of a potential project is a type of community engagement that seeks to gain support and input for project activities. It exists on a spectrum that may range from a highly collaborative process that integrates community interests to simply meeting minimum regulatory requirements of public consultation.

Engaging with communities solely to placate community members and minimize project opposition has no place in today's recommended practices. In the best-case scenario, community engagement can facilitate a collaborative process that enables developers to be forthcoming about constraints while ensuring that the siting is collaborative with the community.[29]

Some regulatory processes include specific public engagement steps, but these steps may not always result in sufficient community engagement. For example, the National Environmental Policy Act (NEPA) requires public input for projects that involve federal agencies, federal funding, or federal permits. Additionally, some state environmental protection acts require public input for projects or actions that significantly affect the quality of the human environment.

Unfortunately, if community engagement is not timely, communities can perceive this as the last stage to oppose projects. Failing to engage sooner could lead to an antagonistic and non-collaborative relationship between communities

29 Apex Clean Energy. 2009. "Who We Are." Exploring Wind Vermillion. https://www.exploringwindvermillion.com/who.

and developers rather than the launching of a long-term relationship and dialogue. Proactive and early engagement using the iterative Four-step Framework, as described above, and accompanying principles is recommended.

2. Implementing Community Engagement Best Practices

Recognizing and addressing community concerns cannot be reactive but must be proactive, starting early in project development. A compendium of implementation best practices for all stakeholders—federal and state agencies, local governments, Tribal governments, private citizens, and public interest groups, as well as industry—to strive for best practice community engagement, as well as to meet any accomplish the regulatory objective more effectively, is further outlined in Appendix C. It is especially important that developers take a voluntary approach to implementing best practices in jurisdictions where community engagement requirements are poorly defined. Utilizing the community engagement model, developers, industry groups, government, and communities can work collectively to adopt and continuously improve effective engagement practices that encourage project development and transport.

3. Developer Articulation of Community Value and Recognition of Value by the Community

When proposing a project or action, it is important to explain the value it creates for the communities affected by it. To do this effectively, a clear definition of value should be established as the basis for engaging with, and gaining insight from, the communities. To arrive at a clear definition, those proposing the action should try to understand the perspective of local community members and consider how and why the proposed action is relevant to their lives; it is important to recognize that perception of both value and impact will differ between communities, based on local factors and histories. This approach can help foster more meaningful and sustained community engagement. It is crucial that the impacted communities recognize the value of the proposed action and identifying and communicating this value will require active listening and understanding.

4. Challenges Relating to Community Engagement

Engagements are subject to a variety of variables that may impact the quality of outcomes, which should be considered before and throughout the engagement process. Public engagement can bring numerous benefits to a project by fostering positive relationships with local communities, aligning project goals with community interests, and providing valuable insights and feedback. However, if not approached with care, public engagement can lead to broken trust, failure to align project goals with community interests, rejection of potential projects, and undermining the legitimacy of institutions involved.[30] Different stakeholders will have different perspectives that can be challenging when building that trust. Considerations that stakeholders will bring to the conversations can vary based on several factors, and this will be the case whether they are citizens; local, Tribal, or regional governments; or community groups:[31]

- Locally oriented stakeholders may have stronger interest in local pollution, economic opportunities, and operational impacts.
- Regionally oriented stakeholders can focus on interjurisdictional concerns such as utility rates or transportation routes and regional air or water pollution issues.
- National or even global stakeholders might focus on the relationship to overall GHG emissions reduction commitments, including methane.

If project sponsors cannot explain why a natural gas GHG emissions reduction project is needed and how it is part of a national or global GHG emissions reduction goal, then the

30 Nash, Jennifer, and Daniel Walters. 2015. "Public Engagement and Transparency in Regulation: A Field Guide to Regulatory Excellence." Penn Program on Regulation. https://www.law.upenn.edu/live/files/4709-nashwalters-ppr-researchpaper062015.pdf.

31 Perciasepe, Robert to Marilu Hastings. Personal interview. Zoom, September 14, 2023.

developer may have more difficulty building community trust. The following are some potential challenges that may arise during community engagement:

- **Information challenges**: The credibility and authority of information sources and the concept of truth that the public and communities rely on may produce a gap in obtaining knowledge or understanding of a topic, technology, or stakeholder, or in community trust levels of the messenger.
- **Amplified voice of vocal minority**: Public engagement may provide an opportunity for a vocal minority to have outsized representation, which can amplify specific sentiments (e.g., "not in my backyard"). Community engagement plans should be designed to effectively and openly solicit input representing the whole community.
- **Special interests influence:** Community engagement can create opportunities for powerful interests to overwhelm or mislead public sentiments for personal or group gain.
- **Community misrepresentatives**: Not all opinions expressed by community member(s) accurately reflect the interest or the concerns of the broader populace. It is, therefore, essential to understand the community, properly identify relevant stakeholders and directly impacted community members, and seek to hear from them. Their interests may conflict, and it's important that these different perspectives are represented anyway.
- **Nonexpert decision-making**: For highly technical projects, engaging communities in a manner that helps them understand the project in layperson terms reduces the risk of them seeking inexpert information to shape their understanding of the project.
- **Insufficient methods for addressing concerns and grievances**: Parties participating in engagement with communities should assess and analyze which communication and engagement mechanisms and tools are available and relevant to specific audiences and community members. An assumption should not be made that all avenues of engagement are appropriate for every audience or group, even if they appear to be from the same community. Documenting engagements, timely follow-up on concerns, and use of grievance mechanisms can help establish credibility, accountability, and trust.
- **Cost constraints**: Community engagement involves convening public hearings, advisory committees, providing educational tools, facilitating small and large group discussions, and collecting, analyzing, and responding to community needs and concerns. These efforts require travel, sustained relationships and partnerships, trained personnel, database management, and facilitators, which can impose cost constraints that may be difficult to overcome.
- **Diminishing returns**: If community members do not trust that project developers will implement their interests or authentically address their concerns, engagement may result in diminishing returns where the process may be perceived as performative and increase mistrust.
- **Delayed decision-making**: Meaningful engagement takes time to ensure a balance of community interests with project developer capabilities to address concerns before a decision can be made. This may result in protracted decision-making.
- **Expectation gap**: Communities have diverse needs and priorities that may require different types of investments and collaborations. However, some needs may fall out of the scope of what a private company or group of companies may address; as a result, government or nongovernmental actors may be better suited to address them. It is necessary to set clear expectations at the beginning and during the engagement process regarding the impact mitigations and benefits. This includes defining how the involved parties can realistically participate or play a role. These expectations may also create tension among stakeholders.
- **Unintended consequences**: Opening projects to public engagement could result in unintended consequences such as increased land prices, access to confidential information, etc.

5. Community Benefits Plans

Currently, some Justice40-covered programs[32] funded by the Infrastructure Investment and Jobs Act and Inflation Reduction Act require applicants to develop and submit Community Benefits Plans (CBPs), including hydrogen hubs and carbon capture and storage. CBPs are a new engagement and benefit-sharing process and model that require project developers to plan for and participate in proactive community and labor engagement, among other key elements.[33] While a new approach that should be evaluated for efficacy—including across projects of differing scales—CBPs may offer a useful model for project developers to consider when planning GHG emissions reduction projects in the NGSC. The expansion of the use of CBPs beyond Justice40-covered programs may enable greater engagement, participation, and prosperity sharing with communities potentially impacted by GHG emissions reduction activities.

JOINT FINDING 5: DOE is encouraging a broad cross section of project developers to embed transformative community engagement into their federal deployment and research projects by requiring developers to submit community benefits plans (CBPs) when applying for DOE competitive grants applications. The sufficiency of CBPs, which also includes requirements for meeting workforce, diversity, equity, inclusivity, accessibility, and Justice40 goals, typically comprises between 10% and 20% of the applicant's overall score when evaluated. DOE has also begun to include CBPs requirements in some formula grant applications.

JOINT RECOMMENDATION 4: *The NPC recommends, after comprehensive review of their effectiveness, that DOE consider expansion of its Community Benefits Plans/Planning (CBP) approach beyond the Infrastructure Investment and Jobs Act and Inflation Reduction Act for all funded programs and projects. Thus, CBPs would be required beyond Justice40-covered programs to other government funding streams in domestic energy development. If the DOE expands CBPs beyond covered programs, it should publicize the nonconfidential aspects of CBPs to promote best practices sharing.*

JOINT RECOMMENDATION 5: *The NPC recommends that DOE consider funding research on the impact of best practices in community engagement, both through case studies and quantitative analysis. This research could be conducted by academia independently with industry providing support either through trade associations or partnerships formed with academia. This would provide valuable insights into the outcomes of best practices in community engagement and help improve future engagement efforts.*

JOINT FINDING 6: DOE should seek to systematize the adoption of community engagement best practices in the context of energy development to ensure broad adoption. DOE would benefit from collaboration with an independent organization on United States-specific considerations in addressing unique socioeconomic and demographic needs.

JOINT RECOMMENDATION 6: *The NPC recommends that the U.S. government charter national and/or regional public/private council(s) of excellence in effective industry-community engagement practices to develop and encourage the adoption of best practices that include equal representations from industry, community organizations, and government.*

These councils should be forums where industry, community organizations, and government would keep community engagement best practices up to date by identifying and

32 DOE. 2020. "Justice40 Initiative." https://www.energy.gov/diversity/justice40-initiative.

33 DOE. 2022. "About Community Benefits Plans." https://www.energy.gov/infrastructure/about-community-benefits-plans.

disseminating effective community engagement practices leveraging existing best practice resources (e.g., *Permitting Council FY22 Recommended Best Practices Report*, API RP-1185, and IPIECA) that are cognizant of regional and local needs and considerations. The governance structures, participation processes, and transparency should be designed to: promote engagement of industry, community organizations, local governments, and other interested parties, and enhance the credibility of a council's products.

These councils should intentionally support less-capitalized operators to implement these best practices inclusive of, but not limited to, experienced resources and training.

While acknowledging that many developers already implement community engagement, there is an opportunity to encourage broader adoption of documented best practices across the industry by providing additional motivation to implement robust community engagement. The NPC further recommends the administration and Congress develop government procedural or permitting timeline incentives for companies that consistently meet established best practices (when developed and documented) for community engagement. As part of the joint industry organization, the organization would design a voluntary program to monitor adherence to and adoption of recognized best practices that can be considered for eligibility for procedural or permitting timeline incentives.

B. Testing the Community Engagement Model

The study achieved limited, although critical, participation from community and EJ groups. To help address this gap, the study commissioned focus group field work in six locations across the United States—relevant to the NGSC—to deepen understanding of what place-based community concerns are, what good engagement looks like to them, and what trade-offs they are aware of and willing to accept in support of reducing natural gas GHG emissions. Using messages and themes that emerge from the focus group process, a poll of the six regions was deployed to test the validity and prevalence of community concerns in the same regions.

As a first step in exploring these issues and increasing understanding of how communities perceive engagement around projects and activities to reduce GHG emissions from the NGSC, the study undertook a research effort to test the community engagement model described above and depicted in Figure 2-2.

Hudson Pacific, a public opinion research and communications firm, was enlisted by the NPC to conduct a series of six focus groups over the first three weeks of September 2023. The focus groups were followed by a survey of Americans living in natural gas production regions, near terminals or, in the case of one location, in a large natural gas consumption market. The communities included in the research were:

- Longmont, Colorado
- Odessa, Texas
- Williamsport, Pennsylvania
- New York, New York
- Port Arthur, Texas
- Stonewall-Shreveport, Louisiana

The purpose of the opinion research was to explore the relationship between residents of energy-intensive communities (locales of natural gas production, distribution, and use) and energy developers' community engagement practices. Insights were sought to assess whether engagement with these communities in advance of projects and activities to reduce GHG emissions from the NGSC might lead to better decision-making and outcomes for the community and industry.[34] Among other things, this research revealed how effective engagement might work and the principles that should underpin the approach.

34 While the intent of the facilitated discussions was to test the community engagement model as it applies only to reducing GHG emissions from the NGSC, discussions with residents often evolved naturally into discussions of energy development generally and community experiences with various types of energy-related activities, from oil and gas development, to pipelines, to power generation. The observations from the focus groups and associated poll may, therefore, not be exclusive to the NGSC or GHG emissions reduction activities.

Full results from the focus groups and survey are included in Appendix C.

The results of this research indicate that participants agree on the importance of community engagement, but achieving these desired outcomes will require significant commitment and resources. Industry may need to overcome public skepticism to set a new standard for engagement. Effective interaction with communities is not something most residents reported experiencing. The industry also will need to work to overcome deep cynicism to convince some people that community engagement can benefit everyone involved.

1. Emerging Themes and Observations

- **The idea of engagement appeals to people.** In theory, residents think energy-related infrastructure changes in their communities would be better with community engagement than without. They would expect the process to include companies exploring the needs of the community, listening to residents, understanding their perspectives, collaborating on solutions, and taking meaningful actions. Further, energy development that is "more responsible" (e.g., reducing pollution, alternative energy) likely would yield more and better engagement from a community.
- **The prospect of engagement buoyed and energized some residents.** Engagement would be a departure from residents' current experience. The possibility of being acknowledged, heard, and considered imbued them with a palpable sense of agency, especially in the smaller communities.
- **The benefits of engagement are not top of mind, but they are not inaccessible.** Pressed for how companies might benefit, people readily identify improved relations with the community, better employee relations, reduced public opposition, and better government relations.
- **Residents in some focus groups pointed out that government has a role in engagement as well.** They pointed out that voters have a say in these matters by way of voting for their elected representatives at the local, state, and federal levels who enact zoning ordinances, laws, and regulations that govern the siting, construction, and operation of the energy installations as well as any technology modifications or additional infrastructure. Poll results on the topic of shared responsibility are summarized in Table 2-1.

When it comes to ensuring that the benefits of natural gas development are fairly distributed in a community, how much of a role do you think each of the following organizations *should* have?	Major Role
The oil and gas industry	62%
Your local government	56%
U.S. Department of Energy	53%
Your state government	44%
An advisory group made up of representative community members	43%
Local college and university experts	18%
An outside, third-party organization	14%

Table 2-1. Roles in Ensuring Community Benefits Distribution

JOINT FINDING 7: Inadequate community engagement practices have led to distrust of project developers and delays in projects.

Figure 2-3 illustrates a hierarchy of community engagement practices. The levels in the pyramid correspond to levels of engagement described by focus group participants. The pinnacle in this illustration, or the "interpersonal" level, represents how community members described engagement they considered most ideal. Conversely, the base of the pyramid, or "regulated/required," illustrates the most basic level of engagement experienced by focus group participants. When focus group participants were asked, unaided, how oil and gas and other companies currently interact with their communities, their experiences did not resemble the highest-order engagement that sits atop the pyramid in Figure 2-3. Instead, a hierarchy emerged that started at the base—"regulated/required," with the most basic principle of a license to operate—and built toward engagement. In the associated poll, when presented with a list of community engagement activities, half of the survey respondents said none of them were happening in their communities, or at least they were

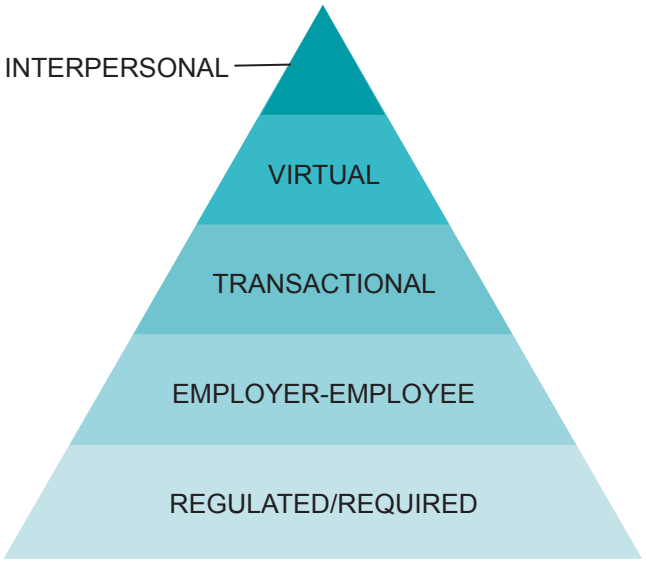


Figure 2-3. *Hierarchy of Community Engagement*

not aware of them. Activities that represent the bottom of the hierarchy were the most frequently cited community engagement activities experienced or perceived by poll responders.

- **Regulated/required:** As discussed earlier, some focus group participants described a license to operate that required only for operators to follow zoning laws as well as local and state regulations. They did not think that a company was obligated to do anything beyond that because their focus is to make money and anything more than gaining an institutional license to operate would increase costs.
- **Employer-employee:** With most participants in the focus groups, the license to operate rested most heavily on whether a company was a good employer. Jobs functioned as social currency. Better jobs—those that are stable and offer benefits such as healthcare and a 401(k), for example—enhanced the reputation of the company that offered them. In the survey, respondents who had a favorable impression of the way the oil and gas industry operate in their communities (roughly half of them) overwhelmingly said that it was because of jobs.
- **Transactional:** This is what most people associate with engagement; something that goes beyond the employer-employee relationship. It involves companies "giving back" to, or contributing to, the progress of the communities in which they operate, which can take the form of school programs, new or improved facilities, community amenities, among other things we understand as a form of corporate social responsibility or being a good corporate citizen. The outreach activities most cited in the survey were making contributions to local charities (25%), educational institutions (23%), and events in town (such as a sporting event or parade) (21%). A quarter also said that the industry had shared safety information with residents. In focus groups, participants described these types of activities positively, but some found them to be transactional and self-serving.

None of these bottom three levels of the pyramid involve the ongoing, two-way communications that characterize true engagement, and fewer than one in five respondents reported experiencing activities that would be characterized as engagement as represented in the upper levels of the community engagement illustration.

- **Virtual:** Virtual engagement involves opportunities for social media and online engagement. This level does not offer the rich interaction that helps define the top of the pyramid, but virtual engagement does afford the opportunity for a community to offer input and feedback. We heard throughout the focus groups that this would be a necessary component when engaging younger generations, who are much more accustomed to engagement via social media platforms than in person.
- **Interpersonal:** The top level of the pyramid represents the highest-order community engagement described in the five-step framework discussed above. Following the community engagement model set forth, interpersonal community engagement creates the most value for all parties and results in the most constructive partnerships between communities and companies.

2. Obstacles to Meaningful Engagement

Residents of these energy-intensive communities have mixed attitudes about the oil and gas industry operating in their communities. They

largely have a favorable view of them (54%, versus 31% neutral and 12% unfavorable), but just 28% trust the oil and gas industry a great deal to do the right thing for their communities (roughly half had some trust). And a plurality think that both benefits and costs are distributed unfairly (four in ten for both).

Broadly speaking, the public is cynical about the prospect of corporate engagement. In annual Gallup polling on public confidence in societal institutions, large corporations typically rank near the bottom. In June of 2023, only 14% of adults in the United States said they have quite a lot or a great deal of confidence in large corporations, just six points higher than Congress, which received the lowest rating of 16 institutions.[35]

Focus group participants think of corporations as primarily profit-seeking institutions that are reactive, not proactive, so they cannot imagine companies would pursue engagement unless they needed to. While the cynicism should not be surprising, it can help to inform a serious and meaningful approach to engagement.

Meaningful engagement would need to be characterized by transparency, honesty, and authenticity. If approached in that manner, participants stated that a company that engages in ongoing, two-way engagement could differentiate itself from operators that do not practice effective engagement within their community.

35 Saad, Lydia. "Historically Low Faith in U.S. Institutions Continues." *Gallup,* July 6, 2023. https://news.gallup.com/poll/508169/historically-low-faith-institutions-continues.aspx.

There was a small group of participants who questioned the need for engagement. Their views ranged from those who pondered why a company would go to such lengths to develop relationships with community members to those participants who are hostile to the idea. Others wondered why a company would engage the community when it could accomplish its goals without engagement. Still, more than nine in ten survey respondents agreed that efforts should be made to ensure that the benefits and costs of future energy developments are distributed more fairly in the community.

In the end, companies need to clearly articulate the purpose of engagement. People do not expect, or even trust, that companies engage out of a sense of altruism. Also, the novelty of the approach is partly to blame; it will be new to people and runs counter to the public perception of how companies operate. The best way for a company to inoculate itself against such skepticism is to acknowledge the novelty of the approach and be transparent and honest in what it hopes to achieve through the community engagement process.

3. Reactions to the Engagement Model

The community engagement model depicted in Figure 2-4 (same as Figure 2-2) was presented to focus group participants for their consideration and feedback. Ideally, engagement is an ongoing cycle that begins with thoughtful exploration and is further characterized by dialogue, internalization, collaboration, and visible outcomes.

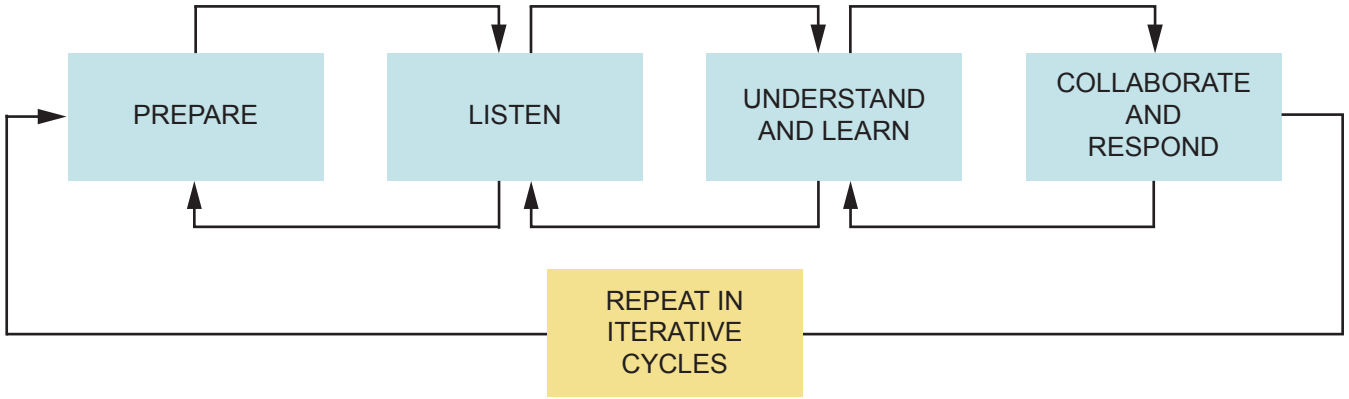


Figure 2-4. *Community Engagement Best Practices Model*

Each step in the proposed engagement process model was discussed individually to discover how residents interpreted each. Notably, engagement cannot take a one-size-fits-all approach for every community.

- **Prepare: Learn about the community and its needs.** Determining whether, and to what degree, to engage a community should be assessed in the "Prepare" phase of community engagement. If a company seeks open communication, it is imperative that the company learn something about residents, their goals, and the community. The operator needs to explain how it is going to help the community achieve its immediate and long-term vision. A participant described this phase as, "if you're (a company) coming into my community, you should have done your homework about where we feel like we're headed and say, 'this is how we're going to help with that vision for your community.'"
- **Listen: Communities have a profound desire to be heard.** The best way a company can demonstrate engagement is by talking to the community, asking them what they need, and explaining how they want to help positively impact the community. Numerous participants articulated that they do not want their communities considered for development through executive decision-making and without being engaged in decisions.
- **Understand and learn: Communities desire open, transparent communication.** Participants want to engage in two-way dialogue so that both parties understand each other's needs and ensure that the engagement is healthy and productive. The suggestion was made to conduct community surveys to identify needs.
- **Collaborate and respond: Be willing to work together and act.** Participants emphasized the importance of companies following through and taking the actions promised. If a community expresses concerns about a proposed action, the company needs to explain their solutions and then implement them. If companies do not take the actions pledged, communities will be unlikely to come back to the dialogue.
- **Repeat iteratively: Maintain long-term commitment to communities.** Companies need to stay active in the community and maintain relationships with residents.

C. Foundations for Effective Community Engagement

1. Transparency

Residents want information provided as transparently as possible and their questions to be answered so that they understand what is happening in their community. They do not want to have to do research on their own. Participants stated that it is the company's responsibility to explain the proposed project and what community options are. Sharing information is paramount and can lead to rebuilt trust.

2. Accountability

Participants explained that corporations need to take responsibility for their mistakes to build credibility and trust with the community. For the energy industry, comments indicated that some companies failed to accept accountability for environmental and community impacts. It is important to engage with the impacted community to repair relationships and address problems.

3. Respect

Community members want to be heard, respected, and taken seriously. They perceive that the energy industry has ample resources and much at stake to drive them to implement community engagement best practices.

4. Acknowledge Fear of Change

In several of the groups, residents mentioned that "people don't like change." Some participants explained that, even if the change is positive, some community members will react negatively out of fear. Overcoming this fear will be especially important through ongoing community engagement and corporate commitment.

5. Recognize the Unreachable

Participants observed that some people will never participate in community engagement activities or be supportive of change or development. Some people do not care, some are too busy, and some are too hardened on either political extreme.

One participant stated it succinctly when describing how a company needs to approach a skeptical community: "They're (the community) not going to believe us (the company) until they see it. And if you're honest, then we'll see it. And again, it will be worth it."

The NGSC has its own history and context of engagement with communities, which are explored in the next section.

D. Differentiation Through Effective Modern SCI Practices

In the evolving social context related to communities affected by natural gas project development, some corporations are increasing their community engagement to meet demands, resolve value differences, set priorities, research problems, and implement solutions.[36] The benefits that can accrue to corporations, regardless of industry, from this level of engagement include reduced investment and shareholder risk, improved social and environmental innovation, increased trust-based relationships that in turn provide resources and information, improved employee relations, and enhanced reputation and brand value.[37, 38, 39] However, while producing value to a company, social issue participation also can be costly.[40] So, the more effective the community engagement, the more efficient the use of resources can be. Thus, through the process of establishing and managing collaborative relationships between companies and their stakeholders and communities, companies may develop new, intangible resources, including new capabilities, enhanced reputation, and social capital, which in turn can lead to opportunities for differentiation.[41] By extension, the capabilities accumulated by companies that address impacts—from reducing methane emissions and other GHG emissions to authentically engaging with EJ communities—may result in higher order reputational and social capital across stakeholder groups.

1. Examples of Industry Guidance on Community Engagement

In recent years, oil and natural gas industry activities have garnered increasing public scrutiny. Operations along the entire supply chain, including even midstream maintenance, have encountered outspoken opposition, raising increased interest in improved community and public engagement. Additionally, the industry can easily be painted with a broad brush, so one incident from a late adopter can discolor industry-wide advances or improvements. To mitigate this challenge, industry has proactively developed leading practices to guide companies, including Recommended Practice *(RP) 100-3, Community Engagement Guidelines,* for upstream companies, and *RP 1185, Pipeline Public Engagement*, for pipeline operators.[42, 43] These documents provide a framework for companies to approach topics, including stakeholder identification and collaboration, EJ, and information sharing for the life cycle of energy assets amid many, sometimes duplicative, government requirements. In our four-step model for community engagement, and by reference to API guidelines for community engagement RP 100–3, the study team recognizes the importance of engaging with all relevant members of the community. The Houston Energy Transition Initiative also developed guidance for community

36 "Stakeholder Theory." http://www.stakeholdertheory.org.

37 Harrison, J.S., Bosse, D., and Phillips, R.A. "Stakeholder Theory and Competitive Advantage." *Academy of Management Proceedings* 2007. (1): 1–6. https://doi.org/10.5465/ambpp.2007.26530469.

38 Shook, E., Lacy, P., Suntook, C., and Rademacher, J. "How Stakeholder Alignment on Sustainability Unlocks a Competitive Advantage." World Economic Forum. February 2022. https://www.weforum.org/agenda/2022/02/how-to-strengthen-sustainability-by-engaging-with-stakeholders.

39 Freeman, R. Edward. 2010. "Strategic Management." Cambridge University Press. https://doi.org/10.1017/cbo9781139192675.

40 Hillman, Amy J. and Gerald D. Keim. 2001. "Shareholder Value, Stakeholder Management, and Social Issues: What's the Bottom Line?" *Strategic Management Journal*. 22(2): 125–39. http://www.jstor.org/stable/3094310.

41 Hastings, Marilu. "A New Operational Paradigm for Oil Operations in Sensitive Environments: An Analysis of Social Pressure, Corporate Capabilities and Competitive Advantage." 1999. *Business Strategy and the Environment* 8 (5): 267–80. https://doi.org/10.1002/(sici)1099-0836(199909/10)8:5%3C267::aid-bse215%3E3.0.co;2-e.

42 American Petroleum Institute. RP 100-3. "API Publishes Community and Stakeholder Engagement Standard for Upstream Operations." April 4, 2024. https://www.api.org/news-policy-and-issues/news/2024/04/04/api-publishes-community-stakeholder-engagement-standard-upstream-operations.

43 American Petroleum Institute. RP1185. "Pipeline Public Engagement." 2024. https://publications.api.org/documents/1185_e1-PubAcc/html5.html.

engagement. The report *Climate Equity Framework and Toolkit for an Equitable Energy Transition in Greater Houston* describes the current state of regional community engagement and provides a toolkit of resources and information for companies starting work on climate equity and community engagement.[44]

2. Community Engagement Drivers and Actions Across the NGSC

The structure of the oil and gas industry is complex, as described in Chapter 1 of the report. Large operators, those that may have decades of community engagement experience in socially diverse settings while operating internationally, may already possess some capabilities to address SCI issues. However, medium-sized, and less-capitalized operators might not have the same type or level of experience managing community impacts. Newer and domestic-focused firms might be addressing SCI issues in a robust way for the first time and may face unique challenges in adapting their current community engagement practices to today's expectations.

In addition to possibly varying across company size, SCI capabilities might also vary across different segments of the industry—from upstream through the midstream and downstream—due to different drivers and actions of community engagement to address SCI issues.

RECOMMENDATION 7: ***The NPC recommends, as community engagement best practices become formalized and consolidated, that trade associations or other industry groups develop specific community engagement training programs for their members that target specialized needs of upstream, midstream, and downstream operators; and whether they are large, medium, or less-capitalized firms.***

Several case studies from across some segments of the NGSC illustrate the different drivers that spur companies to address SCI and the levers used to implement their SCI strategies.

a. Case Study 1: ConocoPhillips Learning to be a Good Neighbor: Alaska North Slope

For ConocoPhillips' operations in Alaska, there are four essential components to being a good operating neighbor. Engagement, transparency, respect, and time. ConocoPhillips Alaska has operated in Alaska for more than 50 years. Development on Alaska's North Slope in the 1970s and 1980s progressed at the Prudhoe Bay and Kuparuk River Fields, both large fields on land owned by the state of Alaska. In the mid-1990s, the Alpine Field was discovered to the west of these fields. The Alpine Field sits just outside of the eastern boundary of the National Petroleum Reserve–Alaska (NPR-A) in the Colville River Delta. The Alpine Field is on land owned by the state of Alaska with some oil and gas rights co-owned by an Alaska Native Regional Corporation and some surface rights owned by an Alaska Native Village Corporation. The Alpine Field is also located near the village of Nuiqsut, an Indigenous community of about 400 residents who depend on subsistence resources such as caribou, birds, fish, and bowhead whale. Development on these traditional lands comes with a large responsibility, one that requires the company to embrace what it means to be a good neighbor, one that engages in respectful dialogue, listens to concerns, collaborates on solutions, and creates shared value from the company's operations.

Effective community engagement begins with getting to know stakeholders and understanding their values, issues, and concerns. This takes time–time spent in community meetings, city council meetings, participating in events, and visiting with community elders. For example, conceptual development of the Alpine Field took more than eight years. That time was spent engaging with local leaders, identifying their expectations, listening to and incorporating, community feedback, conducting studies, sharing information, and navigating the regulatory process. Hearing from the community about the importance of the land to their identity and culture, ConocoPhillips designed environmental studies, which helped establish baseline

44 Houston Energy Transition Initiative. "Climate Equity Framework and Toolkit for an Equitable Energy Transition in Greater Houston." April 2024. https://htxenergytransition.org/wp-content/uploads/2024/04/04.02.24_Climate-Equity-Report.pdf.

conditions, document wildlife patterns and use, and evaluate potential effects of development on the environment. These studies, along with community feedback, helped guide the design and placement of facilities to minimize the development's impacts on wildlife, land, water, the community, and subsistence access. This approach continues today through community meetings, email updates, employment of subsistence representatives to monitor company activities, and on-site ConocoPhillips' Village Outreach staff.

Important to the community engagement program is the creation of value for the local community from ConocoPhillips operations and the recognition of the relationship. The company organizes a Career Quest program to inspire high school students to pursue a future at the Alpine Field, invites community members to dinner at the ConocoPhillips camps, and hosts community celebrations. ConocoPhillips helped form the Nuiqsut Community Development Foundation, which was established to plan and build community infrastructure and provide mutual aid in times of emergencies. The Alpine Field also provides natural gas to Nuiqsut, which replaced diesel fuel for power generation, and fuel oil heaters in the homes. This improved overall community health and air quality, and reduced energy costs, which helps offset the high costs of living in the Arctic.

But the real test of effective community engagement comes during times of disagreement. Over the years, there have been projects that have faced objections from the community. For example, in 2017, ConocoPhillips proposed a drilling an exploration well about 2.5 miles from the village, which was closer than any previous drilling activity. As potential impacts were raised by the community, the company postponed the project to address these concerns. Ultimately, mitigation measures were developed in collaboration with the community to limit impacts and provide appropriate monitoring. Examples included utilizing Tier IV generators, a type of diesel generator with the lowest emissions available, to power the rig to reduce emissions and installing remote air monitoring stations between the rig and the village, which ultimately helped gain community support for the project. Effective solutions are developed through the investment of time and willingness to listen.

It has been more than 25 years since the discovery of the Alpine Field. The company's good-neighbor relationship with Nuiqsut continues to grow and evolve as new generations grow up and continue their cultural and subsistence traditions. Throughout this time, the fundamentals have not changed: engagement, transparency, respect, and time. Engage by getting to know each other, support transparency by maintaining open lines of communication, respect individuals and the land on which the company operates and incorporate ample time to support the first three pillars. This approach reinforces a focus on solutions that positively impact the community.

b. Case Study 2: Devon Energy Community Engagement: Barnett Shale, Benbrook Lake, Texas

Community engagement is a critical element of oil and gas business development. While businesses may have the permitted license to operate, it is critical to their success to maintain the social license to operate. Devon Energy defines elements of a social license to operate as including corporate citizenship, building quality relationships, environmental and community goodwill, positive social impacts, employee recruitment and retention, and brand favorability.

During the development of the Barnett Shale in North Texas, Devon Energy sought to develop assets adjacent to communities surrounding Benbrook Lake. There were multiple challenges for both Devon and the local communities, mainly land use, site construction, public safety, traffic, freshwater resources, and air quality.

Because Devon's business activity and the local community's shared space and resources are intertwined, it was imperative for Devon to engage with community members prior to, during, and after operations activity in the area. As a first step, roughly two months prior to beginning development, Devon held open house-style engagement sessions to seek, and ultimately maintain, the social license to operate in the Benbrook Lake region.

The open house forums were held for community members to learn about Devon's operations plan and the potential impacts of the plan. Additionally, these meetings included printed materials and community engagement professionals representing Devon who engaged with residents and business owners to answer questions and better understand the community's perspectives, requests, and concerns. Through the open house forums, Devon received candid feedback from the community participants who wanted to ensure that environmental health and safety remained a priority. Example themes from the community engagement discussions include traffic-related public safety, freshwater use, and air quality.

To address the community charge of ensuring air quality and freshwater use are managed properly, Devon pioneered a method of recycling produced water and eliminated flaring during operations. Devon also employed traffic safety support along with speed limit signage and monitoring for construction traffic.

Thanks to the intentional and constructive relationship with local communities, Devon was able to maintain its social license to operate and was successful in developing the Barnett Shale assets in the region. The surrounding communities received benefits during Devon's operations through a Devon employee-supported volunteer program and community grants designed to address local needs as outlined throughout the community engagement process.

c. *Case Study 3: Cheniere's Societal Considerations and Impacts of Liquefied Natural Gas Projects: Texas and Louisiana*

Cheniere's Sabine Pass Liquefaction facility was the first large-scale LNG export project in the Lower 48 authorized by the Federal Electric Regulatory Commission (FERC) in 2012. The company's Corpus Christi LNG Project, authorized by the FERC in 2015, was the first greenfield LNG export project in the United States. As a relatively new sector of the energy industry in the United States, LNG projects have faced unique and specific challenges as projects have developed and started operations.

i. *Local workforce*

As the first wave of LNG export projects were developed in the 2010s, there was no existing LNG workforce in the communities where these facilities were to be located. Most of the technical expertise in the LNG field existed abroad. To support a local workforce, local students and residents needed access to central technical tenets of the LNG industry, such as cryogenics and liquefaction.

Cheniere built relationships with local schools and colleges in southwest Louisiana, southeast Texas, and South Texas to understand the educational curriculums and programs that existed for local students and identified existing gaps specific to the LNG industry.

The company made financial investments in local colleges to help purchase custom liquefaction and regasification units so that students could simulate conditions faced on the job at an LNG plant.

Cheniere partnered with those local colleges in Texas and Louisiana to create apprenticeship programs specific to the LNG industry. These apprenticeships deliver a unique experience that combines education with on-the-job experience in either process technology, instrumentation technology, or millwright. The program combines one year of classroom education toward an associate degree with one full year of hands-on training at an LNG plant alongside experienced professionals. Apprentices receive financial grants to offset tuition costs.

Cheniere sponsors apprenticeship programs at SOWELA Technical Community College in Lake Charles, Louisiana, and Del Mar College in Corpus Christi, Texas. In 2022, the company partnered with Lamar State College in Port Arthur, Texas to establish new apprenticeship programs for process technology and instrumentation, and electrical.

These efforts have resulted in more local students receiving custom educations in industry-specific specializations that makes them competitive in the hiring process at LNG projects in their communities. Since the creation of these

apprenticeship programs in 2018, 36 people, 57% of eligible apprentices, have been hired by Cheniere.[45]

ii. Developing local content

As LNG export projects developed, some communities have faced challenges in deriving benefits for residents when it comes to opportunities for employment and benefits for local businesses. There have been challenges regarding how local contractors and vendors can compete for business with large, complex organizations that often partner with a multinational engineering, procurement, and construction contractor to construct the facility.

The size and scale of an LNG project can be overwhelming to communities unaccustomed to large energy infrastructure projects, and residents, community organizations, and local businesses are not always prepared and equipped to conduct business with such large companies and their engineering, procurement, and construction contractors.

To advance the local supplier base and help small businesses gain the capacities they need to compete for industry-wide opportunities, Cheniere partnered with the Coastal Bend Business Innovation Center at Texas A&M University-Corpus Christi to create the Doing Business with Giants professional development program. This program helps local entrepreneurs and small businesses develop business models that align with and fulfill industry supply chain needs. Participants attend a series of workshops, which cover everything from cash-flow management to business planning and insurance requirements. Those who attend are eligible for company-funded grants of up to $20,000.

Along with project partners Bechtel and Baker Hughes, Cheniere cohosted a local supplier workshop in Portland, Texas designed to engage local small businesses that could provide goods and services in support of local LNG operations. Participants attended sessions discussing supplier equity, procurement processes, and peer-to-peer networking. The engagement with local businesses, business organizations, and other partners opened the door to opportunities for local suppliers to conduct business with large LNG projects and provided significant benefits to local residents and businesses. Nearly $90,000 was awarded to local small businesses who participated in the Doing Business with Giants program in 2022. Additionally, nearly 40 local suppliers and nine partners engaged in the local supplier workshop in Portland, Texas and left with a better understanding of how to conduct business with the LNG facility and its partners in the region.

d. Case Study 4: SCI Considerations by Less-Capitalized Operators

As discussed throughout the study, Charting the Course study leadership hosted a series of workshops across natural gas-producing regions with less-capitalized operators' (LCO) representatives. One component of the discussions was to gain insights about LCO approaches to social issues and community engagement within their operating areas. As hypothesized, due generally to the more local nature of their operations and interactions with community members, LCOs tend to focus engagement activities on local impacts and stakeholders rather than broader or national-level groups. The individuals that lead or work for LCOs are often part of the fabric of local communities where they operate and are possibly neighbors and fellow landowners and community members. They may participate with their neighbors in school, faith-based organizations, or other community activities. Thus, they might experience direct impacts on their social capital and reputations with friends and neighbors if their community engagement activities are seen as inadequate. LCO community engagement activities reflect their proximity and daily interactions with their neighbors.

LCOs shared their community engagement observations and practices with local communities that include:

- Regardless of background, the more an LCO engages with communities and keeps them informed, the more the engagement and the

45 Cheniere Energy, Inc. "Cheniere Highlights the Power of Connection in 2022 Corporate Responsibility Report." August 9, 2023. https://lngir.cheniere.com/news-events/press-releases/detail/283/cheniere-highlights-the-power-of-connection-in-2022.

operator's efforts are appreciated. Without needing to share sensitive information, communities appreciate the time and effort an LCO puts into keeping their neighbors informed about activities and plans. This mutual benefit helps develop trust between the operator and the community.

- For LCOs that work in Tribal areas, daily engagement with their Tribal communities occurs. As they stated during the workshops, Tribal interactions by LCOs are conducted on a different level than other types of operators. The Tribes need to be informed and part of the decision-making process.
- LCOs seek to break down barriers and avoid missteps with communities where they operate. They particularly look to hire from local communities and stay involved with community leaders.
- Communities are generally focused on local concerns, perhaps more than global concerns like climate change or energy poverty. Many of the complaints that LCOs receive are about nuisance issues like noise during field operations, or concerns about things like seismicity (related primarily to water disposal operations). Efforts to resolve these concerns are essential to continuing good relations with communities.

IV. TRADE-OFFS: POTENTIAL IMPACTS AND BENEFITS

Reduction of GHG emissions from the NGSC is viewed as a net benefit on a national and global scale, but there may also be benefits and impacts at a local and regional level from these activities and projects. Many people live near natural gas development operations[46] where many GHG emissions reduction activities will be located, and some communities might be disproportionately exposed to the impacts of those activities.[47] For example, the potential benefits and cobenefits of reducing flaring and methane emissions in terms of air quality improvements might not be distributed homogeneously among various subpopulations. The focus groups and poll that this study commissioned support the notion that communities, including those related or proximal to NGSC infrastructure, experience trade-offs when they negotiate benefits versus potential or experienced impacts.

Determining whether benefits of GHG emissions reduction activities are distributed equitably among the affected populations might include assessment of which communities could be benefited or harmed by specific changes in siting or operations, and whether those communities are disadvantaged communities. The trade-offs between benefits and impacts must be examined to determine the roles government and industry should play in reducing burdens on impacted communities.

This section considers trade-offs that fall broadly into two categories—economic and health—that are relevant to potential GHG emissions reduction across the NGSC. The section seeks to understand some of the trade-off considerations within these categories to support building an understanding of net benefits and cobenefits to impacted communities that result from activities and projects that reduce and/or offset GHG emissions across the NGSC. One trade-off consideration is the tension between the global benefits of reducing climate change risk due to GHG emissions reduction and the local community impacts experienced from activities to reduce GHG emissions. Several recent studies are devoted to a robust understanding of these dynamics, including the U.S. government's *Fifth National Climate Assessment*.[48] As such, this chapter does not devote additional study to this area but notes that local and regional climate impacts and dynamics should be considered when developing projects and activities that reduce GHG emissions from the NGSC.

A. Exploring Trade-Offs in Study Poll

As detailed in Section III.B., focus groups and a poll were conducted in communities proximal to,

46 Czolowski, E.D., Santoro, R.L., Srebotnjak, T., and Shonkoff, S.B.C. 2017. "Toward Consistent Methodology to Quantify Populations in Proximity to Oil and Gas Development: A National Spatial Analysis and Review." *Environmental Health Perspectives.* 125 (8): 086004. https://doi.org/10.1289/ehp1535.

47 Johnston, J.E., Chau, K., Franklin, M., and Cushing, L. 2020. "Environmental Justice Dimensions of Oil and Gas Flaring in South Texas: Disproportionate Exposure among Hispanic Communities." *Environmental Science & Technology* 54 (10): 6289–98. https://doi.org/10.1021/acs.est.0c00410.

48 Global Change Research Program. 2023. "Fifth National Climate Assessment." https://nca2023.globalchange.gov/.

or relevant to, the NGSC to ascertain perspectives on the community engagement model and learn from community members about trade-offs they might make in assessing responses to projects and activities of reducing GHG emissions reduction from the NGSC. The poll asked respondents to consider if they would be receptive to the installation, for example, of a natural gas pipeline in their neighborhoods if they received some benefits in return. While a relatively large proportion of residents (roughly a third in each case) responded "not sure" to the hypothetical question, a slim majority of respondents expressed willingness if there were something in it for them:

- 52% would be willing if the development included GHG-reducing technology
- 52% would support the pipeline if their energy bills would be lowered (they would expect a 28% reduction on average)
- 47% would be willing if the development provided jobs and economic benefits to the community

Respondents were divided as to whether they would be willing to pay more on their energy bills for certifiably cleaner air, water, and land resources. Forty percent of respondents were unwilling to spend anything, and less than one-third of respondents were willing to spend $10/month for certifiably cleaner air, water, and land resources. The data from this poll suggest these items may not be something most energy consumers are willing to pay a large premium for:

- 40% would not be willing to pay more
- 29% would pay $10 per month
- 20% would pay $20 per month
- 10% would pay $50 per month

These trade-offs may be made by individuals or communities, in the short term or long term, between economic factors or health factors, or between local and global considerations. These trade-offs are complex, often localized, and difficult to ascertain as they are often made at an implicit level.[49, 50] The next section highlights some of the larger categories of potential trade-offs between impacts and benefits that communities proximal to locations where GHG emissions reduction activities or projects are planned might already be experiencing.

B. Economic Benefits and Impacts

Economic benefits are a major factor when it comes to communities accepting energy infrastructure. Workforce considerations, including direct and indirect employment, are often prioritized. However, even if there are positive economic impacts, this does not necessarily guarantee project acceptance by communities as trust, engagement, and a balance between negative and positive impacts also play important roles. Local procurement or investment can be important drivers of realizing local economic benefits, as they often have a spill-over effect, creating economic and business opportunities that support a wider network of community members through employment, tax revenue generation, and potential skills development.[51]

Energy development and associated activities can have significant impacts on physical infrastructure in a community, such as roads, housing, water supplies, and other utility and municipal and community services. Balancing the need for housing for workers coming into a project area while also maintaining housing and rental prices to retain current residents can be an important, but challenging, balance to achieve. Many energy and infrastructure companies demonstrate a focus on economic benefits through philanthropic efforts in various operational contexts. States that are economically reliant on natural resource development benefit significantly from these philanthropic efforts, e.g., in Alaska, annual corporate financial contributions range between $2 and $10 million.[52]

Commodity industries like oil and natural gas experience cyclicality that can manifest in rapidly

49 Thaler, Richard H., and Cass R. Sunstein. 2008. *Nudge: Improving Decisions about Health, Wealth, and Happiness.* New York: Penguin Books. ISBN 13: 978-0143115267.

50 Kahneman, Daniel. 2011. *Thinking, Fast and Slow.* New York: Farrar, Straus and Giroux. ISBN 13: 978-0374533557.

51 For examples of how industry is conducting training and building contractor capacity, see references in this trade association blog: https://www.api.org/news-policy-and-issues/blog/2023/01/13/diversity%20equity%20and%20inclusion%20progress%20made%20and%20whats%20to%20come.

52 Simonelli, Isaac Stone. "Alaska's Giving Pipeline." *Alaska Business Magazine.* May 2020. https://digital.akbizmag.com/issue/may-2020/alaskas-giving-pipeline/.

increasing and decreasing economic activities. Global supply and demand for natural gas and some domestic policy and regulatory impacts may also contribute to these economic cycles that have impacts on communities. GHG emissions reduction activities in and around areas where energy is a primary economic driver may also contribute to economic fluctuations. Growth in the NGSC, including GHG emissions reduction activities, could also create cyclical economic community impacts that should be considered by governments and investors and included as a factor in wider-scale community benefit planning. Where natural gas facilities are colocated with disadvantaged communities, consideration should be given to avoiding and mitigating potentially adverse impacts of GHG emissions reduction.

FINDING 8: Supply and demand for oil and natural gas and some domestic policy impacts contribute to economic cycles that have historically impacted many local communities near energy infrastructure/development locations. GHG emissions reduction activities in the natural gas supply chain may be colocated with communities who have been impacted by such cycles. Their experience with these cycles may inform their receptivity to GHG emissions reduction activities and projects.

RECOMMENDATION 8: ***The NPC recommends that federal, state, and local agencies analyze, design, and deploy multisector, model community-industry-government partnerships focused on addressing the economic impacts of GHG emissions reduction activities on communities.***

1. Workforce Development and Job Creation

Recognizing that we cannot separate natural gas jobs from GHG emissions reduction jobs of the NGSC, a focus on carbon intensity reduction actions will be built on the foundation of the existing NGSC workforce. Any change in a supply chain, whether through applications of new technology for emissions reduction or shifting flows to different parts of the supply chain, will affect that workforce. The workforce may require training and skills development on the use of new technology and practices and may need to be deployed to different locations as future natural gas flows change among supply chains.

Workforce development and job creation are two key issues commonly voiced in surveys of energy-impacted communities.[53] Concerns regarding the type of jobs, and the ability of the local workforce to fill available jobs, in the associated energy sector activity are paramount. A study of communities that are economically tied to the NGSC could consider what requirements should be in place to address potential economic issues resulting from GHG emissions reduction activities. The results of this study could inform what actions governments and investors could pursue to capture job benefits for local communities. Disadvantaged groups, including those who are unemployed, should be considered by developers of GHG emissions reduction projects for employment opportunities.

Industry progress to reduce the carbon intensity of natural gas through GHG emissions reduction activities in the NGSC offers possibilities to redeploy some of these workers in new roles and locations. Recent studies have considered which communities are most economically dependent on fossil fuels and assess additional social economic and environmental risk factors they may face.[54, 55] One study shows many fossil fuel workers have the right skills already—the problem is that those new jobs likely will not be in the same location, adding a critical trade-off dynamic. While the Resources for the Future (RFF) study was in the context of a shift away from fossil fuels, it offers a conclusion that is relevant to this GHG emissions reduction study, "(t)he key issue

53 Cozzi, Laura, and Brian Motherway. "The Importance of Focusing on Jobs and Fairness in Clean Energy Transitions–Analysis." International Energy Agency. July 6, 2021. https://www.iea.org/commentaries/the-importance-of-focusing-on-jobs-and-fairness-in-clean-energy-transitions.

54 Lim, J., Aklin, M., and Frank, M.R. 2023. "Location Is a Major Barrier for Transferring U.S. Fossil Fuel Employment to Green Jobs." *Nature Communications,* 14 (1): 5711. https://doi.org/10.1038/s41467-023-41133-9.

55 Resources for the Future. "Communities Dependent on Fossil Fuels Are Vulnerable to Socioeconomic, Environmental Stressors." December 14, 2021. https://www.rff.org/news/press-releases/communities-dependent-on-fossil-fuels-are-vulnerable-to-socioeconomic-environmental-stressors/.

is to remember that no two places are alike, and local solutions will differ depending on local circumstances."

The NGSC has created a specialized workforce, which has supported rapid expansion of the industry in the United States,[56] with many of these highly skilled employees having spent their careers in the NGSC. Natural gas supply chain operators should ensure that opportunities to implement GHG emissions reduction actions are made available to retain these highly skilled workers.

The approaches to mitigate GHG emissions from the NGSC have been evolving rapidly. A government-industry-academic study to understand the potential implications of this evolution of the workforce could help identify new employment opportunities and risks to workforce retention. Such a study could also assess the real impact on the workforce and identify new opportunities for job creation where GHG emissions reduction projects would be too costly and otherwise result in premature cessation of operations.

FINDING 9: Local workforce and job creation solutions depend on local circumstances and require meaningful community engagement.

FINDING 10: Workforce development and job creation is specific to each location, based on the type of natural gas activity at that location and the work needed to mitigate GHG emissions there. GHG emissions reduction activities will precipitate impacts on segments of the natural gas supply chain differently. There is a need for more information and data related to the workforce for the natural gas sector and how it might be deployed to GHG emissions reduction activity skills within different segments of the industry.

RECOMMENDATION 9: *The NPC recommends that DOE, with guidance from its 21st century Energy Workforce Advisory Board,[57] commission a comprehensive study to look at any mismatch between the skills of the current natural gas supply chain workforce and skill needs for implementing GHG emissions reduction projects. This study would serve as a blueprint for policy and investments to address human capital needs to deliver the country's GHG emissions reduction goals.*

2. Tax Revenue Benefits and Impacts

Economic growth can be a byproduct of successful industrial development through job creation, local business creation and revenue increases, supply chain activity, and governmental revenue. Ultimately, increasing economic prosperity to improve services and programs benefiting a community's well-being must be developed around a local community's priorities and the realities of that context.

Communities benefit from development in many ways. Local taxation of infrastructure and local supply chain businesses allow for communities, municipalities, and states to access revenue and capital to invest locally. Projects or activities that reduce GHG emissions from the NGSC may produce similar benefits, although at a reduced or limited scale. These enhancements can improve local and regional infrastructure, benefiting industry and the community. Conversely, industrial activity in counties/parishes can impact local communities differently, depending on the level and timing of the industrial expansion. The new development of GHG emissions reduction infrastructure within the NGSC may help diversify the local economy. A recent study looking at the economic benefits associated with carbon capture retrofit opportunities at existing industrial facilities as well as the expansion of CO_2 transport infrastructure, shows that reduction of GHG emissions from the NGSC has the potential to be a multibillion-dollar opportunity with a diverse

56 Bozick, R., Gonzalez, G., Ogletree, C., and Gehlhaus Carew, D. 2017. "Developing a Skilled Workforce for the Oil and Natural Gas Industry an Analysis of Employers and Colleges in Ohio, Pennsylvania, and West Virginia." RAND Corporation. https://www.rand.org/content/dam/rand/pubs/research_reports/RR2100/RR2199/RAND_RR2199.pdf.

57 DOE. 2023. "21st Century Energy Workforce Advisory Board (EWAB)." https://www.energy.gov/policy/21st-century-energy-workforce-advisory-board-ewab.

array of opportunities and economic benefits available to states and regions.[58]

Many communities rely on severance taxes and royalties to support basic community infrastructure. These same communities may eventually have the most to gain from GHG abatement to support longevity of operations. A recent study from RFF[59] identified communities that could be economically harmed but environmentally benefited by the transition away from fossil fuel production and operations. This study can also be used for insights regarding which communities may eventually find GHG abatement important to support resiliency of natural gas production and associated revenues. RFF includes a tool that pinpoints where economic changes are likely to be concentrated. In the study, more rural and more economically distressed counties are often more vulnerable to the loss of fossil energy production. Previous work looking at tax revenues in energy-producing states has found that state and local governments benefit from a variety of revenue sources associated with oil and gas production, including severance taxes, leasing revenue, property taxes, and sales taxes, but these sources vary from state to state.[60]

Table 2-2 provides an overview of the types of state and local revenue generated from energy development. It is important to note that the total revenue generated from energy development and production can vary dramatically depending on geography, resource availability, and existing industrialization of the region. In communities that have limited existing infrastructure, issues arising from rapid, large-scale industrial buildout may not allow for sufficient time for a ramp-up in local services such as road repair and local emergency services. In some cases, this lack of infrastructure can result in large new costs for local governments, and local revenue may not be sufficient to manage increased demand for services.

For regions that have for decades been highly reliant on oil and gas as an economic driver and tax base, decreasing production and declining revenues, which could also occur due to the costs of GHG emissions mitigation, could impede the ability to provide services to residents in these communities. Maintenance of these revenue streams is vital to supporting these communities. RFF's 2024 study also estimates per capita revenue and reports this by county with a range of findings that cover the role of both government revenue and wages. To summarize, the report finds, "It is clear that the energy sector plays a major role in supporting government services across the United States, and efforts to dramatically reduce GHG emissions will have major consequences for these revenue streams and the services they support."[61]

C. Regional Case Studies in Revenue Sharing

The following sections explore several regional case studies. These examples look at both benefits in different regions and ways that some communities are particularly reliant on shared revenues from natural gas production. These communities may eventually attach particular importance to GHG abatement to extend the longevity of natural gas production. In addition, the revenue-sharing examples also illustrate how benefits are shared in some communities. While GHG abatement does not generate revenue, policy proposals to promote valuation of GHGs (and develop markets) could one day make it easier to capture and better distribute value from abatement.

1. Tribal Experiences Including Revenue Sharing

Tribal experiences with natural gas development (and GHG emissions mitigation) are unique

58 Larsen, J., Hiltbrand, G., Herndon, W., and King, B. 2021. "The Economic Benefits of Industrial Carbon Capture Investment and Employment Opportunities for Eastern and Western States." https://rhg.com/wp-content/uploads/2021/01/The-Economic-Benefits-of-Carbon-Capture-State-Investment-and-Employment-Estimates_Phase-II.pdf.

59 Resources for the Future. 2021. "Communities Dependent on Fossil Fuels Are Vulnerable to Socioeconomic, Environmental Stressors." https://www.rff.org/news/press-releases/communities-dependent-on-fossil-fuels-are-vulnerable-to-socioeconomic-environmental-stressors/.

60 Resources for the Future. 2024. "The Energy Transition and Local Government Finance: New Data and Insights from 10 U.S. States." https://www.rff.org/publications/working-papers/energy-transition-local-government-finance-renewables-revenue/.

61 Resources for the Future. 2024. "The Energy Transition and Local Government Finance: New Data and Insights from 10 U.S. States." https://www.rff.org/publications/working-papers/energy-transition-local-government-finance-renewables-revenue/.

Revenue Instrument	Deployed by	Basis for Revenue	Allocated to
Severance tax	State	Value or volume of oil/gas prodcution, number of wells drilled	Varies by state
Lease payments	Federal, state, county, muni	Negotiated lease terms and royalties	State, county, muni
Property taxes	County, muni	Value of oil/gas property (definitions vary by state)	County, muni
Sales tax	State, county, muni	Value of sales (rates vary by locality) affected by oil- and gas-related economic activity	State, county, muni
In-kind	County, muni	Negotiated agreements or donations	County, muni

Table 2-2. *Local Government Revenue Sources Associated with Oil and Gas Development*

in several important ways. For example, Indigenous populations of the continental United States and Alaska generally experience poverty and economic disadvantages due to historic inequities, and, as a result, economic development is a major shared concern among Tribes. Each Tribe also has a unique approach to natural gas and energy resource development and GHG emissions mitigation. These approaches include provisions for the protection of sensitive environmental and/or cultural resources. The history of self-determination or lack thereof also impacts decision-making and the process of development, including both Tribal NGSC and GHG emissions mitigation.

To advance NGSC GHG emissions mitigation in Tribal areas, open communication is required to effectively engage all communities, but due to the lack of effective engagement in past energy development in Indian Country, care must be taken to avoid performative community engagement, with great emphasis on Tribal decision-making processes.[62]

For example, the treatment of Tribal lands as public lands under the NEPA has posed challenges for Tribes wishing to develop mineral resources. NEPA requires an analysis of environmental impacts for all projects which have a federal nexus (i.e., projects that require a federal agency to take action). For Tribes, pursuit of projects and infrastructure to support the reduction of GHG emissions from the NGSC is fraught with additional approvals and authorization from the federal government. Leasing, right-of-way, and NEPA approvals are required elements for Tribal infrastructure projects which would not be required from similarly situated private projects. As initial GHG emissions reduction efforts from the NGSC will resemble traditional fossil energy projects involving construction and operation of physical infrastructure, these myriad approvals will result in delays in approval and construction of projects for GHG emissions reduction.

Where efforts to reduce NGSC GHG emissions will involve investments on Tribal lands or in Tribal communities, governments and investors will need to consider that, for meaningful progress to be made in addressing historic inequities related to energy development in Tribal communities, consultation and respect for sovereignty and self-determination must be the primary drivers. Benefits from such engagement and consultation can include: 1) local economic development for Tribal communities and regional economic development for the community at large, 2) an equity stake in development projects for Tribes, and 3) regional energy resilience and domestic energy security.

The Southern Ute Indian Tribe has led an effort over the past 15 years to mitigate emissions due

62 "Indian Country" means (a) all land within the limits of any Indian reservation under the jurisdiction of the United States government, notwithstanding the issuance of any patent, and, including rights-of-way running through the reservation, (b) all dependent Indian communities within the borders of the United States whether within the original or subsequently acquired territory thereof, and whether within or without the limits of a state, and (c) all Indian allotments, the Indian titles to which have not been extinguished, including rights-of-way running through the same. https://www.justice.gov/archives/jm/criminal-resource-manual-677-indian-country-defined.

to naturally occurring methane seepage from coal seam outcrops on the reservation. Specifically, it is using horizontal well technology along a seeping coal seam outcrop to capture the natural gas and bring it to market. Pursuing regional-specific opportunities like this is important to GHG emissions mitigation efforts in Tribal communities and these types of successful partnerships and can provide a blueprint for Tribes throughout the U.S. to achieve greater involvement and decision-making in NGSC activity, GHG emissions mitigation, and distribution of benefits across membership.[63]

In Alaska, the Alaska Native Regional Corporations can, as private landowners with mineral rights, develop resources where they have the mineral rights, but they are subject to the same regulations as any other mineral developer in the U.S., which may also impact GHG emissions mitigation. The Alaska Native Claims Settlement Act (ANCSA) created various mechanisms and corporations to share revenue with Alaskan Natives and compensate these shareholders for lands lost in the settlement—with the intent that the land should be used and developed for the economic and cultural benefit of the Alaska Native shareholders.

As in the Lower 48, Alaskan Native cultural values and existing NGSC revenue-sharing models are not monolithic and could impact GHG emissions mitigation approval and adoption. As for the revenue sharing, ANCSA requires distribution of 70% of any revenue derived from the development of certain natural resources on a regional corporation's land, while 30% stays with the corporation. The important role of benefits accruing in Alaska is discussed further in Section IV.C.5. Today, Alaska Native Corporations make up seven out of the top 10 Alaska-based companies,[64] providing many benefits, including dividends, employment opportunities, and scholarships for higher education to their respective shareholders.

Tribal energy departments can be effective stewards of Tribal natural resources and provide direction and implementation of Tribal GHG emissions mitigation goals to support Tribal energy sovereignty and self-determination.

Some Tribes have taken the additional step of starting their own departments of energy to manage Tribal energy and mineral resources more effectively. Such departments typically handle land use and right-of-way permitting, royalty and severance tax collection and concurrence or approval of proposed projects. The case for an in-house department of energy within Tribal government is dependent on the specific energy resources and means for development of each Tribe.

FINDING 11: **The current permitting system for Tribes throughout the United States is based on treatment of Tribal lands as public lands, which presents hurdles to infrastructure development associated with GHG emissions reductions from the natural gas supply chain.**

RECOMMENDATION 10: ***The NPC recommends that the federal government work toward more efficient and effective approval of projects on Tribal trust lands, while respecting Tribal sovereignty and self-determination to support GHG emissions reductions with Tribes, a key stakeholder.***

2. A Gulf of Mexico Experience with Sharing Revenue Benefits

Creating ways to share benefits across different levels of government could become important to realizing GHG emissions mitigations, particularly with respect to earning more local support. An interesting example is found in recent history.

In 2006, the U.S. Congress enacted the Gulf of Mexico Energy Security Act (GOMESA), which created a revenue-sharing model among Texas, Louisiana, Mississippi, and Alabama. Each of

63 Tribes, including the Navajo Nation, Jicarilla Apache, and Southern Ute have implemented Tribal severance taxes on oil and gas production in addition to federally mandated royalty payments. This severance tax provides an additional source of revenue for Tribes to finance Tribal operations, social programs, or to utilize for other economic development. Utilization of such revenue may be through revenue sharing models which utilize permanent fund endowments, revenue accumulators, or other vehicles to distribute revenues effectively and equitably to Tribal members.

64 "Top 49ers: Local Companies Ranked by Gross Revenue." 2023. *Alaska Business Magazine.* https://www.akbizmag.com/lists/top-49ers/.

these oil and natural gas-producing Gulf states, including their political subdivisions of counties or parishes, receive a portion of the revenue from certain offshore oil and gas production leases in the Gulf of Mexico. Additionally, a portion of these funds are also shared with the state assistance program within the Land and Water Conservation Fund (LWCF), administered by the Department of the Interior.

Disbursements from GOMESA directly fund coastal conservation, restoration, and hurricane protection projects across the participating states, and the LWCF fund supports preservation, development, and access to outdoor lands for public recreation. The Department of the Interior distributed more than $353 million in fiscal year 2022 revenues to the four states, the largest annual disbursement to date. Since its inception, $1.65 billion has been shared with the coastal states and their subdivisions through GOMESA.[65]

Since 2007, 37.5% of all qualified Gulf revenues have been shared among the four states and their coastal political subdivisions. This is in addition to the 12.5% of revenues that are disbursed to the LWCF. A combined cap of $500 million for the states and LWCF applies in most years.[66]

In recent years, Congress has considered legislation that would change GOMESA's revenue-sharing provisions, specifically, potentially removing the cap on shared revenues, increasing the state-shared percentage, expanding the set of leases from which revenues can be shared, and adding additional states that would share revenues from the program.

Another programmatic tool worth noting is the Coastal Impact Assistance Program (CIAP)[67] that was established to assist states that supported, or had been impacted by, oil and natural gas development along the outer continental shelf. This included Louisiana, Texas, Mississippi, Alabama, Alaska, and California, along with their individual coastal parishes or counties.

CIAP was created through the Energy Policy Act of 2005 and was funded with approximately $1 billion in dedicated royalty revenue from offshore oil and gas leases during 2007-2010. The program was sponsored by the U.S. Fish and Wildlife Service and funds were intended for the conservation, protection, and preservation of coastal areas, including wetlands.

3. Permian Basin and the Permian Strategic Partnership

Since 2007, Texas' oil and gas industry has paid more than $230 billion in state and local taxes and state royalties and employed more than 480,000 Texans. This revenue directly funds public schools, universities, roads, first responders, and other essential services. It also significantly funds public education, particularly the Permanent University Fund and the Permanent School Fund. In FY2023, each of these funds received more than $1.8 billion. Additionally, independent school districts in Texas received oil and natural gas property taxes totaling $2.81 billion. Counties across Texas received millions of dollars in property taxes paid by the oil and natural gas industry, totaling $885 million in FY2023.[68] As Texas navigates the energy transition and looks for opportunities to reduce GHG emissions from various sectors, including the NGSC, the economic benefits of oil and natural gas to local communities underscore the importance of fostering a sustainable, diversified economy that addresses environmental impacts on jobs, revenue, and infrastructure.

Ensuring communities' quality of life is strengthened and improved is important. One example of how this has been addressed is through the Permian Strategic Partnership (PSP), a coalition of 27 leading Permian Basin energy

65 Department of the Interior. "Interior Disburses over $353 Million to Gulf States to Support Coastal Restoration and Conservation." March 30, 2023. https://www.doi.gov/pressreleases/interior-disburses-over-353-million-gulf-states-support-coastal-restoration-conservation.

66 Congressional Research Service. 2022. "Gulf of Mexico Energy Security Act (GOMESA): Background and Current Issues. https://crsreports.congress.gov/product/pdf/R/R46195.

67 Department of the Interior Minerals Management Service. "71 FR 57564: Coastal Impact Assistance Program Guidelines." *Federal Register*, Vol. 71, No. 189, September 29, 2006: 57564. https://www.federalregister.gov/documents/2006/09/29/E6-16090/coastal-impact-assistance-program-guidelines.

68 Riojas, Ethan. 2024. "2023 Annual Energy & Economic Impact Report." Texas Oil & Gas Association. https://www.txoga.org/2023eeir/.

companies and higher education institutions who joined together to work in partnership with leaders across the region's communities to address current and future challenges to the responsible development of the vast oil and natural gas resources of the Permian Basin in the states of New Mexico and Texas. The companies involved with the PSP bring people, expertise, resources, and leadership to develop solutions in partnership with local leaders and communities to help strengthen and improve the quality of life for Permian Basin residents. Through analysis and resident surveys, PSP has identified the five most urgent needs of the region: public education, safer roads, improved healthcare, affordable housing, and workforce development. PSP has taken each of these needs and created committees to focus on each topic and engage with various stakeholders to work toward a solution.

Over the past five years, the PSP has committed $160 million to generate over $1.5 billion in community support.[69] Some examples in recent years include PSP partnering with Cal Ripken to launch a five-year $7.5 million investment that will provide new STEM centers for each of 134 elementary schools in the Permian Basin. Additionally, the PSP and the Permian Road Safety Coalition partnered to invest $3.17 million to fund life-saving equipment to first responders in 26 counties across West Texas and Southeast New Mexico. This partnership builds on the first round of this initiative, previously funded by PSP in 2021 with a $1.1 million donation. To support healthcare and education, PSP and partners have funded the Permian Basin Behavioral Health Center, planning to open in summer 2025. Lastly, part of addressing workforce-related impacts is creating more housing. The PSP Housing Committee is seeking to partner with various organizations and stakeholders to increase housing availability across the Permian Basin and mitigate housing as a barrier to workforce expansion. These are just a few examples of how the industry works together to help communities be more resilient.

69 "Permian Strategic Partnership Transformed $125 Million in 2022 into Over $1 Billion in Collaborative Investment." PR Newswire. Yahoo Finance. June 8, 2023. https://finance.yahoo.com/news/permian-strategic-partnership-transformed-125-153000437.html?guccounter=1.

4. Appalachia

A study of the social consequences in the Marcellus Appalachian region documented community responses of positive and negative impacts of natural gas development activities[70] where GHG emissions reduction activities may occur. Economic benefits were the number one positive impact according to communities. These benefits were not limited to monetary value, but include elements like training opportunities for youth to remain in the local region, thereby creating generational family stability and enhanced financial stability for the elderly, among other benefits. The indirect benefits included themes like long-term business development for alternative sectors, like agriculture—which allowed the community to retain its identity. These factors contributed to a sense of, and improved indicators of, enhanced quality of life.

The negative consequences reported in the study were concentrated around the "ramp-up" stages of development when drilling activities commenced. This included traffic congestion, dirt, noise, damage to existing infrastructure, population increases with "newcomers," increase in crime rates, lack of housing and utility infrastructure, and a lack of trained local workers to support the development activities. Some of the negative impacts extended to the operational or post-production stages of activities, including instances of unfair/unequal treatment of homeowners by energy companies (i.e., signing "bad leases"), minimal royalties, and negative environmental impacts.

5. Alaska

The importance of the NGSC to Alaska (and therefore also its important role in GHG emissions mitigation) is elucidated by its development experience.[71, 72] The evolution of the North

70 Gorman, Mary. 2014. "ScholarWorks Social Consequence, Stakeholder Influence, and Resource Needs for Marcellus Shale Communities." https://scholarworks.waldenu.edu/cgi/viewcontent.cgi?article=1102&context=dissertations.

71 Alaska Permanent Fund Corporation. https://apfc.org/.

72 Alaska Oil and Gas Association. "The Role of the Oil & Gas Industry in Alaska's Economy." January 2020. https://www.aoga.org/wp-content/uploads/2021/01/Reports-2020.1.23-Economic-Impact-Report-McDowell-Group-CORRECTED-2020.12.3.pdf.

Slope in Alaska post-1971 offers an example of the transformative impact of energy development. Prior to the ANCSA of 1971 and the formation of the North Slope Borough (NSB), most residents had limited access to amenities and education. The discovery of the Prudhoe Bay Oil Field in 1968 acted as a catalyst for change. Infrastructure taxes levied by the NSB led to an economic boom, funding improvements in housing, sanitation, education, mental health services, and employment opportunities. The NSB also owns and supports the Barrow Gas Fields, which provide natural gas for multiple uses. Moreover, the economic benefits extend beyond the North Slope. According to the Alaska Oil and Gas Association, the industry contributed $3.1 billion to state and local governments in FY2019, which constituted 38% of the state's general fund revenue. The Alaska Permanent Fund, established in 1976, has witnessed considerable growth, reaching $78 billion by June 2023, and has distributed more than $24 billion to Alaskans thus far.[73] The recently approved Alaska LNG Project,[74] is expected to lower energy costs for Alaskans, create up to 10,000 construction jobs and 1,000 operational jobs and boost the economy through potential revenue from exports.

6. Mountain West

Regional economic development in the mountain west has been linked to oil and natural gas extraction, and areas, including the Four Corners, Montana, Wyoming, and the Dakotas, have become major suppliers of oil and natural gas in the United States, providing energy security for the United States, as well as allies and trade partners in Asia and Europe. These regions suffer from a lack of infrastructure such as natural gas pipelines to bring associated gas to market, resulting in venting and flaring of methane rather than beneficial use. Rapid adoption of GHG emissions reduction technologies can substantially decrease emissions from venting and flaring while providing continued economic opportunities in the energy industry for impacted workers. Additional investment through grants or other opportunities should be provided to these impacted communities to support incremental GHG emissions mitigation efforts and preserving revenue and wages.

V. HEALTH COBENEFITS OF REDUCING GHG EMISSIONS IN THE NATURAL GAS SUPPLY CHAIN

The U.S. oil and natural gas industry is deploying methane-mitigating technologies that allow for more efficient methane leak detection and response, and consequently, reduced methane emissions intensity. These projects and technology interventions have the potential to reduce human exposure to air pollutants generally, especially when coupled with well-designed and thoughtfully implemented policies (see Chapters 1 and 5 of this study for a detailed discussion of policy considerations).[75]

The Centers for Disease Control and Prevention states, "climate change, together with other natural and human-made health stressors, influences human health and disease in numerous ways."[76] The National Academies of Science, Engineering and Medicine states, "(a)dverse health impacts from climate change are extensive and provide some of the most compelling motivation for climate mitigation."[77] Reducing GHG emissions from the NGSC can help to meet national climate goals. Reducing national GHG emissions, including from the NGSC, would mitigate climate change if the reductions are not accompanied by increased emissions elsewhere.

73 Alaska Oil and Gas Association. 2020. "The Role of the Oil & Gas Industry in Alaska's Economy." https://www.aoga.org/wp-content/uploads/2021/01/Reports-2020.1.23-Economic-Impact-Report-McDowell-Group-CORRECTED-2020.12.3.pdf.

74 "Alaska LNG Permits-Alaska LNG." March 27, 2018. https://alaska-lng.com/regulatory-process/permits/.

75 Dougherty, W., Kartha, S., Rajan, C., Lazarus, M., Bailie, A., Runkle, B., and Fencl, A. 2009. "Greenhouse Gas Reduction Benefits and Costs of a Large-Scale Transition to Hydrogen in the U.S.A." *Energy Policy* 37 (1): 56–67. https://doi.org/10.1016/j.enpol.2008.06.039.

76 Centers for Disease Control and Prevention. 2022. "CDC-Climate Change and Public Health-Climate Effects on Health." https://www.cdc.gov/climateandhealth/effects/default.htm.

77 National Academies of Sciences, Engineering, and Medicine. "Accelerating Decarbonization in the United States." 2023. *National Academies Press Ebooks*. https://doi.org/10.17226/25931.

A. Health Benefits of Reducing Emissions of Methane and Coemitted Chemicals

Changes in operations to reduce GHG emissions can affect the emissions of other chemicals coemitted with methane, levels of ambient air pollutants, and by extension, the potential population exposures and health effects. Examples include nitrogen oxides, black carbon (a component of fine particulate matter), particulate matter, and hydrocarbons such as benzene, toluene, ethylbenzene, and xylenes. Other air pollutants form as secondary products of these chemical emissions. For example, ozone and particulate matter are formed by reactions of volatile organic compounds (VOCs), nitrogen oxides (NO_x), and sulfur oxides in the atmosphere, so reducing these emissions can reduce the formation of particulate matter (PM) and ground-level ozone. Reducing ozone concentrations is especially important in natural gas-producing regions that are not in attainment with the EPA's National Ambient Air Quality Standards for ozone.

B. Emissions from Natural Gas Production

Sources within the NGSC have emissions, which can include the natural gas itself (methane and other gases), emissions from drilling and completion fluids (organic gases and particulate matter), diesel and natural gas combustion (VOCs, NO_x, and PM), waste management such as flaring (methane and carbon dioxide), and subsurface geochemical species that coexist with the natural gas (e.g., naturally occurring radioactive material).[78, 79] Organic gases and nitrogen oxides can react to form ozone and particulate matter.[80]

The sulfur content of natural gas can also result in emissions of sulfur dioxide (SO_2) and hydrogen sulfide (H_2S), which (along with VOCs) can react in the atmosphere to form PM. The EPA regulates NO_x, SO_2, and PM because, like some emitted VOCs (e.g., benzene), exposure to these emissions has been associated with both acute and chronic health effects.[81, 82, 83]

The VOCs coemitted with methane vary across regions as a function of variability in natural gas composition. For example, natural gas produced in some regions is referred to as "dry" and consists primarily of methane, while natural gas produced in other regions is referred to as "wet" and contains varying amounts of nonmethane VOCs and other compounds.[84, 85, 86, 87, 88]

78 The Academy of Medicine, Engineering and the Science of Texas Task Force on Environmental and Community Impacts of Shale Development in Texas. 2017. "Environmental and Community Impacts of Shale Development in Texas." doi: 10.25238/TAMESTstf.6.2017.

79 HEI Energy. 2020. "Human Exposure to Unconventional Oil and Gas Development: A Literature Survey for Research Planning." https://www.heienergy.org/publication/human-exposure-unconventional-oil-and-gas-development-literature-survey-research.

80 Nsanzineza, R., Capps, S.L., and Milford, J.B. 2019. "Modeling Emissions and Ozone Air Quality Impacts of Future Scenarios for Energy and Power Production in the Rocky Mountain States." *Environmental Science & Technology*. 53 (13): 7893–7902. https://doi.org/10.1021/acs.est.9b00356.

81 Burnett, R.T., Pope III, C.A., Ezzati, M., Olives, C., Lim, S.S., Mehta, S., Shin, H.H., et al., 2014. "An integrated risk function for estimating the global burden of disease attributable to ambient fine particulate matter exposure." *Environmental Health Perspectives*. 122:397–403; https://doi.org/10.1289/ehp.1307049.

82 Cohen, A.J., Brauer, M., Burnett, R., Anderson, H.R., Frostad, J., Estep, K., Balakrishnan, K., et al., 2017. "Estimates and 25-Year Trends of the Global Burden of Disease Attributable to Ambient Air Pollution: An Analysis of Data from the Global Burden of Diseases Study 2015." *The Lancet*. 389 (10082): 1907–18. https://doi.org/10.1016/s0140-6736(17)30505-6.

83 EPA. 2016. "Climate Change Indicators in the United States." https://www.epa.gov/sites/default/files/2016-08/documents/climate_indicators_2016.pdf.

84 Gilman, J.B., Lerner, B.M., Kuster, W.C., and de Gouw, J.A. 2013. "Source Signature of Volatile Organic Compounds from Oil and Natural Gas Operations in Northeastern Colorado." *Environmental Science & Technology* 47 (3): 1297–1305. https://doi.org/10.1021/es304119a.

85 Goetz, J.D., Avery, A., Werden, B., Floerchinger, C., Fortner, E.C., Wormhoudt, J., Massoli, P., et al., 2017. "Analysis of Local-Scale Background Concentrations of Methane and Other Gas-Phase Species in the Marcellus Shale *Elementa: Science of the Anthropocene* 5. https://doi.org/10.1525/elementa.182.

86 Schade, Gunnar W. and Geoffrey Roest. 2016. "Analysis of Non-Methane Hydrocarbon Data from a Monitoring Station Affected by Oil and Gas Development in the Eagle Ford Shale, Texas." *Elementa: Science of the Anthropocene* 4. https://doi.org/10.12952/journal.elementa.000096.

87 Field, R.A., Soltis, J.J., Pérez-Ballesta, P., Grandesso, E., and Montague, D.C. 2015. "Distributions of Air Pollutants Associated with Oil and Natural Gas Development Measured in the Upper Green River Basin of Wyoming." Edited by Detlev Helmig and Gabrielle Petron. *Elementa: Science of the Anthropocene* 3. https://doi.org/10.12952/journal.elementa.000074.

88 Pétron, G., Frost, G.J., Miller, B.L., Hirsch, A.J., Montzka, S.A., Karion, A., Trainer, M., et al., 2012. "Hydrocarbon Emissions Characterization in the Colorado Front Range: A Pilot Study." *Journal of Geophysical Research* 117 (D4). https://doi.org/10.1029/2011jd016360.

C. Emissions from Natural Gas Flaring

Natural gas is sometimes flared from tall stacks equipped with burners, usually for operational safety reasons or if the natural gas is unable to be economically brought to markets.[89] DOE concluded that flaring represents an identifiable point source of primarily two GHGs, carbon dioxide and methane.[90]

Adelsheim (2022) summarized literature on the composition of flare emissions and noted that reported composition varies depending on whether the natural gas undergoes complete or incomplete combustion, or no combustion in the case of unlit flares.[91] Most of the literature focuses on flaring emissions data for GHGs collected as part of emissions inventories,[92, 93, 94, 95, 96, 97] while some literature focuses on chemicals of concern for human health, such as black carbon, which consists of solid particles that also contribute to warming of the atmosphere.[98, 99, 100, 101]

In addition to emissions of air pollutants such as VOCs and black carbon, flares can be a source of noise (e.g., Ohio EPA[102] and Texas CEQ[103]). Citing concern about exposure to emissions, noise, light, and odors from natural gas flaring, Johnston et al., 2020 studied ethnic disparities in exposure to flaring in the Eagle Ford Shale region of Texas.[104] Johnston et al., reported that in the Eagle Ford Shale region, Hispanic people were more likely than non-Hispanic white people to be exposed to flares.

RECOMMENDATION 11: ***The NPC recommends federal and state public health and other regulatory agencies continue to work together to assess which communities might benefit from, or be harmed by, specific GHG reduction infrastructure siting or operational decisions, policies, and technologies and whether those communities are environmental justice***

89 EIA "Glossary-U.S. Energy Information Administration (EIA)." https://www.eia.gov/tools/glossary/index.php.

90 DOE. 2021. "DOE Flaring and Venting R&D: Reducing Emissions and Developing Valuable Low-Carbon Products." https://www.energy.gov/fecm/articles/doe-flaring-and-venting-rd-reducing-emissions-and-developing-valuable-low-carbon.

91 Adelsheim, Lee Ann. "Natural Gas Flaring Associated with Unconventional Oil and Gas Development: Potential Human Exposures" *HEI Energy,* March 3, 2022. https://www.heienergy.org/publication/natural-gas-flaring-associated-unconventional-oil-and-gas-development-potential-human.

92 Allen, M.R., Fuglestvedt, J.S., Shine, K.P., Reisinger, A., Pierrehumbert, R.T., and Forster, P.M. 2016. "New Use of Global Warming Potentials to Compare Cumulative and Short-Lived Climate Pollutants." *Nature Climate Change* 6 (8): 773–76. https://doi.org/10.1038/nclimate2998.

93 Grant, C.A., Wallace, L.M., Spurgeon, P.C., Tramontano, C., and Charalampous, M. 2019. "Construction and Initial Validation of the E-Work Life Scale to Measure Remote E-Working." *Employee Relations* 41 (1): 16–33. https://doi.org/10.1108/er-09-2017-0229.

94 Lange, T., Rasmussen, M., and Thygesen, L.C. 2013. "Assessing Natural Direct and Indirect Effects through Multiple Pathways." *American Journal of Epidemiology,* 179 (4): 513–18. https://doi.org/10.1093/aje/kwt270.

95 DOE. "Natural Gas Flaring and Venting: State and Federal Regulatory Overview, Trends and Impacts." June 2019. https://www.energy.gov/sites/prod/files/2019/08/f65/Natural%20Gas%20Flaring%20and%20Venting%20Report.pdf.

96 EPA. 2014. "Greenhouse Gas Reporting Program (GHGRP). Final Revisions to Subpart W." Accessed November 5, 2021. https://www.epa.gov/ghgreporting.

97 Zhang Y., Gautam, R., Pandey, S., Omara, M., Maasakkers, J.D., Sadavarte, P., Lyon, D., et al. "Quantifying Methane Emissions from the Largest Oil-Producing Basin in the United States from Space." *Science Advances.* 6:eaaz5120. April 22, 2020. doi:10.1126/sciadv.aaz5120.

98 Gvakharia, A., Kort, E.A., Brandt, A., Peischl, J., Ryerson, T.B., Schwarz, J.P., Smith, M.L., and Sweeney, C. 2017. "Methane, Black Carbon, and Ethane Emissions from Natural Gas Flares in the Bakken Shale, North Dakota." *Environmental Science & Technology* 51 (9): 5317–25. https://doi.org/10.1021/acs.est.6b05183.

99 Weyant, C.L., Shepson, P.B., Subramanian, R., Cambaliza, M.O.L., Heimburger, A., McCabe, D., Baum, E., Stirm, B.H., and Bond, T.C. 2016. "Black Carbon Emissions from Associated Natural Gas Flaring." *Environmental Science & Technology* 50 (4): 2075–81. https://doi.org/10.1021/acs.est.5b04712.

100 Hildenbrand, Z.L., Mach, P.M., McBride, E.M., Dorreyatim, M.N., Taylor, J.T., Carlton Jr., D.D., Meik, J.M., et al., "Point source attribution of ambient contamination events near unconventional oil and gas development." *Science of The Total Environment,* 573 (2016): 382-388.

101 Maskrey, S.A., Mount, N.J., Thorne, C.R., and Dryden, I. 2016. "Participatory Modelling for Stakeholder Involvement in the Development of Flood Risk Management Intervention Options." *Environmental Modelling & Software* 82 (August): 275–94. https://doi.org/10.1016/j.envsoft.2016.04.027.

102 Ohio EPA. 2014. "Understanding the Basics of Gas Flaring." https://dam.assets.ohio.gov/image/upload/epa.ohio.gov/Portals/27/oil%20and%20gas/Basics%20of%20Gas%20Flaring.pdf.

103 Texas Commission on Environmental Quality. 2018. "Typical Oil and Gas Flare Flaring at Oil and Natural Gas Production Sites." https://www.tceq.texas.gov/downloads/compliance/publications/gi/gi-457.pdf.

104 Johnston, J.E., Chau, K., Franklin, M., and Cushing, L. 2020. "Environmental Justice Dimensions of Oil and Gas Flaring in South Texas: Disproportionate Exposure among Hispanic Communities." *Environmental Science & Technology* 54 (10): 6289–98. https://doi.org/10.1021/acs.est.0c00410.

communities or other areas that experience high environmental exposures or other social disadvantages.

JOINT RECOMMENDATION 12: *The NPC recommends that DOE, decision-makers, corporations, researchers, governments, and regulatory bodies should actively commit to comprehensively consider and equitably address societal, environmental, and public health impacts during the development and implementation of GHG emissions reduction projects.*

VI. CONCLUSION: THE PATH AHEAD

The SCI considerations related to reducing GHG emissions from the NGSC have gained prominence in the eyes of government, industry, and communities, especially disadvantaged communities. In response to this high-profile set of complex issues, the NPC included, for the first time, a dedicated, stand-alone study to gain insights into EJ, community engagement, and the trade-offs, benefits, and impacts associated with reducing GHG emissions from the NGSC.

Yet, we remain far from a comprehensive understanding of human and community behavior, choices, preferences, and values around energy development. With social media amplification, changes in societal expectations of justice, and an emerging generation of leaders with different values than past and current generations, pressure will continue to mount on the industry to adopt community engagement best practices. Continued work to reduce GHG emissions by industry and government should include collaboration with communities, especially disadvantaged communities, to deliver improved and equitable societal outcomes.

CUMULATIVE IMPACTS: ASSESSMENT AND TOOLS

EPA defines cumulative impacts as "the totality of exposures to combinations of chemical and nonchemical stressors and their effects on health, well-being, and quality of life outcomes" and cumulative impact assessment as the "process of evaluating both quantitative and qualitative data representing cumulative impacts to inform a decision."[a] The EPA developed a Total Environment Framework to conceptualize the combined influences of the built, social, and natural environments on individuals, communities, and definable subpopulations, such as historically disadvantaged groups.[b] The framework is helpful for envisioning the combined influences of development activities, such as those in the NGSC, on individuals and communities, including both benefits and risks.

Governmental agencies and researchers have been developing frameworks and methods for conducting and communicating cumulative impact assessments that inform policy and regulatory decision-making. Several quantitative and qualitative approaches, like biomarker monitoring and Physiologically Based Pharmacokinetic (PBPK) modeling, can be helpful in assessing chemical and nonchemical stressor exposures and effects. Examples of chemical stressors with the potential to affect health include chemical emissions to air, accidental releases to the land or water, industry-related noise and artificial light, and psychosocial stress from living near industrial facilities, as well as social impacts to culture and communities. An example of a nonchemical stressor with the potential to benefit health is the increased access to healthcare that can occur with job creation.

Even as advances are made with cumulative impact assessment methodologies, several challenges remain. Developing and incorporating high-resolution spatial and temporal data and tools are important for the comprehensive characterization and prioritization of risks and benefits. A specific methodological consideration to enhance cumulative impacts approaches is the inclusion of resiliency and potential benefits. Additionally, it is important to advance methods to account for the timeframe of exposures and the interplay between

various stressors. Finally, it is critical to develop pathways to acknowledge and include community perspectives in the cumulative impact assessments.

Tools for characterizing and visualizing data and the unique attributes of disadvantaged communities represent a growing and complex area of work. For example, available data lead to trade-offs between national-level consistency and local granularity or accuracy. Some possible considerations for understanding existing impacts on communities, such as availability and quality of drinking water, might not be well represented in national datasets. In general, potentially useful datasets and tools vary with respect to their original purpose, context, underlying data and metrics, and frequency of updating, and they are subject to different sources of uncertainty. While these tools are, in large part, focused on health, socioeconomic, and environmental aspects, efforts are ongoing to incorporate additional indicators, such as those from the built environment (e.g., housing burden, impervious surface, and lack of tree canopy). Additional uncertainties include varying definitions and methods of weighting key metrics in screening tools, insufficient characterization of community needs, limited health and socioeconomic indicators, and the need for additional context for tool development and use. As these tools continue to evolve, standardization of included metrics might be beneficial to their use in cumulative impact assessment.[c]

There are challenges involved in moving from the measurement of cumulative exposures to understanding the effects on people. Both cumulative exposures and the causes of health outcomes that community members experience might differ from the perceptions or beliefs of the community members themselves. Going forward, both eliminating uncertainties in the science and building knowledge in impacted communities are important.

While screening tools bring together different indicators of impact, methods of conducting cumulative impact assessments are not well established. Several new holistic approaches to measure stressors and vulnerabilities are under development. It is worth noting that the field of public health has extensive literature relating to "social determinants of health" that continues to evolve, in part due to availability and accessibility to socioeconomic and environmental data. The scope of this literature will continue evolving in parallel to policy efforts to address environmental justice. Importantly, the tools that are being introduced by governments and researchers provide a good starting place for recognizing impacted communities and using that recognition to support best practice engagement. In summary, there is value in moving forward, fully cognizant of the challenges, to define cumulative impact assessment approaches that bring real benefit to communities, industries, and other decision-makers.

Notes:

a. EPA, ORD. 2022. "Cumulative Impacts Research." https://www.epa.gov/healthresearch/cumulative-impacts-research.

b. Tulve, N.S., Geller, A.M., Hagerthey, S., Julius, S.H., Lavoie, E.T., Mazur, S.L., Paul, S.J., and Frey, H.C. 2024. "Challenges and Opportunities for Research Supporting Cumulative Impact Assessments at the United States Environmental Protection Agency's Office of Research and Development." *The Lancet Regional Health - Americas* 30 (February): 100666–66. https://doi.org/10.1016/j.lana.2023.100666.

c. Balakrishnan, C., Su, Y., Axelrod, J., Fu, S. 2022. "Screening for Environmental Justice: A Framework for Comparing National, State, and Local Data Tools." Urban Institute. https://www.urban.org/research/publication/screening-environmental-justice-framework-comparing-national-state-and-local.

Chapter 3

DETECTION AND QUANTITATIVE TRACKING OF GREENHOUSE GAS EMISSIONS FROM OIL AND NATURAL GAS SUPPLY CHAINS

OVERVIEW

The Secretary of Energy requested that the National Petroleum Council (NPC) explore technologies for detecting and quantifying greenhouse gas (GHG) emissions from oil and natural gas supply chains. Emissions of carbon dioxide and methane account for almost all of the GHG emissions associated with the supply chains. Tracking of carbon dioxide emissions is primarily based on fuel consumption and emissions estimates are generally viewed as reliable. In contrast, methane emissions can be challenging to detect and quantify due to the diverse nature and sources of the emissions. While detection and quantification of methane emissions can be challenging, new measurement technologies have emerged over the last five years that are dramatically improving emissions detection and the accuracy of emissions estimates and are providing new insights and data.

Sections I and II of this chapter characterize GHG emissions from oil and natural gas supply chains and describe the ways in which emissions information is used. Section III describes individual emissions detection and quantification technologies and their strengths and limitations. Section IV provides examples of how technologies with complementary strengths can be integrated to provide more complete information about emissions. Sections V and VI discuss how the information from measurement technologies is interpreted and acted on by oil and natural gas operators. Section VII addresses potential barriers to deploying emissions detection and quantification technologies at scale, and Section VIII comments on opportunities for global deployment of the technologies.

Throughout the chapter, the NPC recommends actions by governments and the private sector designed to improve technology performance and to make the information provided by emissions measurement technologies actionable for emissions mitigation. The chapter also recommends actions that would promote the use of advanced technologies in meeting regulatory requirements, both now and as the technologies continue to evolve.

I. CHARACTERISTICS OF GREENHOUSE GAS EMISSIONS FROM OIL AND NATURAL GAS SUPPLY CHAINS

Accurate, quantitative tracking of the GHG emissions from oil and natural gas supply chains is an important element in making progress toward climate goals. While quantification of emissions can be challenging, new measurement technologies are continuing to improve emissions detection and the accuracy of emissions estimates and are providing new insights and data.

Carbon dioxide and methane dominate the emissions of GHGs from oil and natural gas supply chains with relatively small contributions from nitrous oxide. Carbon dioxide emissions from these supply chains are primarily due to the combustion of oil and natural gas, either along the oil and natural gas supply chain or by the end use of the fuels. Emissions estimates for carbon dioxide that result from combustion are based on fuel consumption and are bounded by physical limitations on the amount of carbon dioxide that can be produced for a given fuel under known combustion conditions. In contrast, almost all

methane emissions are due to losses to the atmosphere that occur before fuels reach end users. These can include losses associated with production operations, losses during transfer, storage, and separation of oil-gas mixtures, normal operation of pneumatic devices that vent, incomplete combustion of methane in compressors required for transmission (also known as 'combustion slip'), pipeline maintenance requiring evacuation of gases, and losses in local distribution systems. These emissions can be challenging to estimate accurately due to the diverse nature and sources of the emissions, as described later in this chapter.

Overall, as shown in Table 3-1, contributions of methane and carbon dioxide emissions from oil and natural gas supply chains are comparable in their 100-year global warming potential, when measured from wellhead to delivery to end user. In the 2021 national Greenhouse Gas Inventory, the Environmental Protection Agency[1] (EPA) estimated that GHG emissions from oil and natural gas supply chains, from wellhead up to delivery to end user, totaled 306 million metric tons per year of carbon dioxide equivalents (MMT CO_2e). The emissions by sector are shown in Table 3-1 and are discussed in Chapter 1.

For carbon dioxide, the emissions estimates reported in Table 3-1 are dominated by emissions from the combustion of fuels, largely in process compressors, heaters, and other equipment, with smaller contributions from flaring and the venting of carbon dioxide found in produced gas. Because emissions of carbon dioxide are primarily based on fuel consumption, and because these emissions estimated for these sources are generally viewed as reliable, the remainder of this chapter will focus on methane emissions.

Methane emissions reported in the EPA's GHG emissions estimates, other than combustion slip, are often based on estimated counts of equipment and operations, referred to as activity data. The activity data are multiplied by average emissions associated with individual types of equipment or operations, referred to as emissions factors. Combustion slip, and some other process sources, are estimated based upon assumed process conditions, such as an assumed combustion efficiency,[2] and drivers of the process, such as fuel flow (combustion processes), gas flow (gas upgrading processes), or similar process assumptions.

Supply Chain Segment	Methane (MMT CO_2e)*	Carbon Dioxide (MMT CO_2)	Total (MMT CO_2e)
Natural gas production	46	4	50
Petroleum/associated gas production	24	10	34
Natural gas processing	11	19	30
Transmission without combustion emissions	45	1	46
Distribution	15	0	15
Combustion within the supply chain	0	130	130
Abandoned wells	2	0	2
Total	**143**	**164**	**307**

* Consistent with EPA reporting, a Global Warming potential of 28 is used to convert tons of methane emissions to tons of carbon dioxide equivalents.

Source: EPA, 2023.

Table 3-1. *Methane and Carbon Dioxide Emissions from Oil and Natural Gas Supply Chains, from Wellhead to End Use, in MMT CO_2e*

Multiple measurement studies reported in the scientific literature,[3, 4, 5] have concluded that the collection of methane emissions reported in U.S. national emissions inventories may be

1 EPA. "Inventory of U.S. Greenhouse Gas Emissions and Sinks." Last updated April 2024. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks.

2 Combustion efficiency is the fraction of fuel gas that is combusted to CO_2 and associated combustion products, such as CO. The remaining fuel is emitted, uncombusted, as part of the exhaust stream; this portion is often called combustion slip.

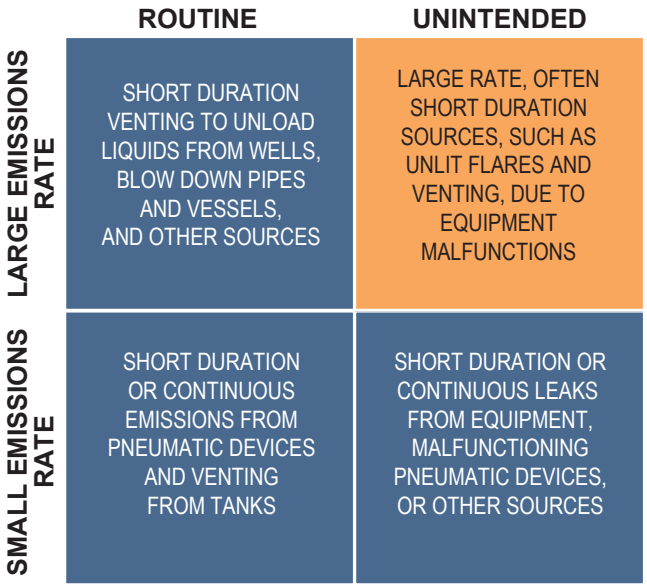
3 Alvarez, R.A., Zavala-Araiza, D., Lyon, D., Allen, D., Barkley, Z., Brandt, A., Davis, K., et al. 2018. "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain." *Science* 361 (6398): eaar7204. https://doi.org/10.1126/science.aar7204.

4 National Academies of Science, Engineering and Medicine (NASEM). 2018. "Improving Characterization of Anthropogenic Methane Emissions in the United States," National Academy Press, Washington, DC.

5 Plant, G., Kort, E., Brandt, A., Chen, Y., Fordice, G., Gorchov Negron, A., Schwietzke, S., Smith, M., and Zavala-Araiza, D. 2022. "Inefficient and Unlit Natural Gas Flares Both Emit Large Quantities of Methane." *Science* 377 (6614): 1566–71. https://doi.org/10.1126/science.abq0385.

underestimated, with discrepancies varying by region, but resulting in a potential underestimate of national methane emissions from oil and natural gas supply chains reported through the U.S. Greenhouse Gas Inventory.[6] The national underestimate has been estimated to be ~60% with significant regional variability.[7] In assessing the reasons why emissions reporting based on activity data and emissions factors often underestimates methane emissions, it is useful to identify categories of emissions. Emissions can be broadly grouped into four categories[8, 9] as shown in Figure 3-1.

As shown in Figure 3-1, emissions from oil and natural gas facilities can have large or small emissions rates that may be anticipated based on facility design and operations (routine), or that may be due to malfunctions or process excursions (unintended). Routine emissions can have large or small rates (left column in Figure 3-1) and may be continuous or intermittent; sources with larger emissions rates typically have short durations. Unintended emissions (right column in Figure 3-1) can also have large or small emissions rates and are generally intermittent, although some may persist for weeks. Emissions rates span more than six orders of magnitude (g/hr to Mg/hr); the threshold separating large and small emissions rates varies widely in the scientific literature, but recent regulatory actions by the EPA effectively define a large emissions rate as 100 kg/hr or more.[10] Overall, characteristics of emissions sources vary widely, and approaches



Note: All these categories require different approaches for quantification; unintended large-emissions-rate events (upper right quadrant) are the most challenging to accurately quantify.

Source: Adapted from Zavala-Araiza et al., 2017, and EPA Science Advisory Board, 2023.

Figure 3-1. *Four Major Categories of Methane Emissions Need to Be Quantified*

for detection and for accurate quantification vary among these different categories of emissions.

Routine emissions that have small emissions rates are generally estimated based on small numbers of measurements performed directly on the sources during discrete measurement campaigns. Average emissions from these measurement campaigns (emissions factors) are multiplied by the number of sources (equipment count or activity factor). For example, based on equipment counts in the EPA Greenhouse Gas Emissions Inventory,[11] there are currently millions of process gas-driven pneumatic controllers at oil and natural gas facilities in the United States. These controllers use gas pressure to open and close valves that control temperature, liquid levels, and pressure. Gas is vented either continuously or intermittently, depending on the design of the controller. The venting results in methane emissions. On average, each individual controller emits at a relatively low rate, but when aggregated over millions of devices, venting

6 EPA. 2024.

7 Alvarez, R.A., et al. 2018.

8 Zavala-Araiza, D., Alvare, R., Lyon, D., Allen, D., Marchese, A., Zimmerle, D., Hamburg, S. "Super-Emitters in Natural Gas Infrastructure Are Caused by Abnormal Process Conditions." *Nature Communications* 8 (1). 2017. https://doi.org/10.1038/ncomms14012.

9 EPA Science Advisory Board. 2023. Science Advisory Board Report on the Scientific and Technical Basis of the Proposed Rule Titled "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." RIN: 2060-AV16. EPA-SAB-23-005. https://sab.epa.gov/ords/sab/r/sab_apex/sab/advisoryreports?session=48648149285.

10 EPA. 2023. "Greenhouse Gas Reporting Rule: Revisions and 24 Confidentiality Determinations for Petroleum and Natural Gas Systems." Accessed on April 4, 2024. https://www.federalregister.gov/documents/2023/08/01/2023-14338/greenhouse-gas-reporting-rule-revisions-and-confidentiality-determinations-for-petroleum-and-natural.

11 EPA. 2023.

from process gas-driven pneumatic controllers is currently one of the largest sources of methane emissions at oil and natural gas production facilities in the United States. Measurement campaigns are performed relatively infrequently and generally on relatively small subpopulations of sources. For example, the studies reported by Allen et al.,[12] the American Petroleum Institute,[13] and Luck et al.,[14] are some of the largest measurement campaigns involving pneumatic controllers and collectively report data on hundreds out of the millions of natural gas-driven pneumatic controllers in use. As operations and equipment designs change, emissions factors and activity data can become outdated. The EPA is currently proposing new emissions reporting requirements[15] that would greatly expand the numbers of measurements on which emissions factors are based. This process may result in operators developing their own emissions factors (e.g., for pneumatics, compressor vents, methane slip), and these data could also improve the accuracy of more generally applied emissions factors. In addition, recent EPA regulations will change the need for some emissions factors as, for example, pneumatic controllers with zero emissions are required. Overall, when accurate activity data and emissions factors are available, emissions from routine, low-emissions-rate sources (lower left quadrant in Figure 3-1) can be reliably estimated.

Emissions rates from routine, high-emissions-rate sources (upper left quadrant in Figure 3-1) can also be reliably estimated if accurate activity and emissions factor data are available. For example, if pipelines or process equipment are depressurized for maintenance or other activities, methane may be vented in a blowdown. Blowdown emissions can be accurately estimated based on the number of events and the volume, composition, and pressure of gas vented; no direct emissions measurements are required for accurate estimates. Other routine, large-emissions-rate, short-duration sources are more difficult to estimate from engineering parameters, and generally rely on event counts, gas pressures, and emissions factors or assumed emissions rates. Examples include the unloading of liquids from a well by allowing the well to vent gas, where measurements are needed to establish accurate emissions factors,[16] or purging of pressurized vessels to eliminate air from the vessels before repressurizing them. Most of these sources have high emissions rates for short durations and overall emissions would be a function of the frequency of the event occurrence and the emissions rate.

Some sources of reasonably anticipated, unintended, and low-emissions-rate sources of emissions (lower right quadrant in Figure 3-1), such as equipment leaks, are also captured using activity data and emissions factors. In these cases, the activity data, such as the counts of leaks, are estimated based on inspections with emissions detection equipment. The emissions factors (amount emitted per leak per equipment type) are estimated based on measurements.[17, 18] Because emissions from these sources are unintended, there is greater uncertainty in these

12 Allen, D., Pacsi, A., Sullivan, D., Zavala-Araiza, D., Harrison, M., Keen, K., Fraser, M., Hill, A., Sawyer, R., and Seinfeld., J. 2014. "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers." *Environmental Science & Technology* 49 (1): 633–40. https://doi.org/10.1021/es5040156.

13 American Petroleum Institute. "API Field Measurement Study: Pneumatic Controllers" EPA Stakeholder Workshop on Oil and Natural Gas. November 7, 2019 – Pittsburgh, PA. 2019. https://www.epa.gov/sites/default/files/2019-11/documents/ghgi_nov2019workshop_tupper2.pdf.

14 Luck, B., Zimmerle, D., Vaughn, T., Lauderdale, T., Keen, K., Harrison, M., Marchese, A., Williams, L., and Allen, D. 2019. "Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations." *Environmental Science and Technology Letters* 6 (6): 348–52. https://doi.org/10.1021/acs.estlett.9b00158.

15 EPA. 2023.

16 Allen, D., Sullivan, D., Zavala-Araiza, D., Pacsi, A., Harrison, M., Keen, K., Fraser, M., Hill, A., Lamb, B., Sawyer, R., and Seinfeld, J. "Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings." *Environmental Science & Technology* 49 (1), 641–648. doi:10.1021/es504016r. 2015.

17 Allen, D., Torres, V., Thomas, J., Sullivan, D., Harrison, M., Hendler, A., Herndon, S., et al. 2013. "Measurements of Methane Emissions at Natural Gas Production Sites in the United States." *Proceedings of the National Academy of Sciences* 110 (44): 17768–73. https://doi.org/10.1073/pnas.1304880110.

18 Pacsi, A., Ferrara, T., Schwan, K., Tupper, P., Lev-On, M., Smith, R., and Ritter., K. 2019. "Equipment Leak Detection and Quantification at 67 Oil and Gas Sites in the Western United States." Edited by Detlev Helmig and Stefan Schwietzke. *Elementa: Science of the Anthropocene* 7: 29. https://doi.org/10.1525/elementa.368.

emissions than for the corresponding low-emissions-rate routine sources.

Finally, unintended large-emissions-rate sources (upper right quadrant in Figure 3-1, highlighted in orange) are generally not well estimated, and these sources have historically been underrepresented in reported emissions inventories.[19, 20] One of the few comprehensive attempts to estimate the proportion of total emissions attributed to large unintended events was performed in the Barnett Shale in north central Texas.[21] Sampling was done in 2013, and approximately half of total emissions were attributed to the largest 1% of emissions measurements (measured emissions rates >26 kg/hr), most of which were classified as unintended. There is significant regional and supply chain variability in the importance of this emissions category. For example, an analysis of approximately 100 tank batteries in an oil producing region of the Permian Basin[22] concluded that 80%–90% of total emissions, found at 10%–20% of the sites, were likely associated with unintended events. Using the same emissions estimation approaches and some of the same measurement approaches, Tullos et al.,[23] found that less than 10% of total emissions were contributed by large unintended events at dry-gas production sites in east Texas. In addition to varying from basin to basin, the frequency, magnitude, and importance of large-emissions events also varies depending on the type of facility. For example, at transmission sites in the United States, 5% of the observed sources accounted for >30% of emissions.[24]

Overall, there is a high degree of uncertainty in the emissions associated with large, unintended events. Measurements to provide better emissions estimates for these large, unintended events would need to sample large numbers of sites, since the events are found, at any given time, at a relatively small percentage of sites and with significant ranges in emissions rates. Sampling would also need to be frequent, since many events are short—minutes to hours—[25, 26, 27]although some may persist for weeks.[28, 29]

FINDING 1: **Methane emissions sources can have large and small emissions rates, can be routine or unintended, and can be both continuous or intermittent; the distribution of these emissions types can vary by supply chain sector, facility type, and location.**

FINDING 2: **The complexity, magnitude, spatial variability, and temporal variability of emissions mean that a wide range of measurement methods, with very different capabilities, are required to accurately characterize methane emissions.**

19 Alvarez et al. 2018.

20 National Academies of Sciences, Engineering, and Medicine. 2018. *Improving Characterization of Anthropogenic Methane Emissions in the United States.* National Academy Press, Washington, DC. https://nap.nationalacademies.org/catalog/24987/improving-characterization-of-anthropogenic-methane-emissions-in-the-united-states.

21 Zavala-Araiza et al. 2017.

22 Stokes, S., Tullos, E., Morris, L., Cardoso-Saldaña, F., Smith, M., Conley, S., Smith, B., and Allen, D. 2022. "Reconciling Multiple Methane Detection and Quantification Systems at Oil and Gas Tank Battery Sites." *Environmental Science & Technology* 56 (22): 16055–61. https://doi.org/10.1021/acs.est.2c02854.

23 Tullos, E., Stokes, S., Cardoso-Saldaña, F., Herndon, F., Smith, B., Allen, D. 2021. "Use of short-duration measurements to estimate methane emissions at oil and natural gas production sites." *Environmental Science & Technology Letters* 8, 463–467. https://doi.org.10.1021/acs.estlett.1c00239.

24 Brandt, A.R., Williams, L., Vaughn, T.L., Quinn, C., Subramanian, R., Duggan, G.P., Willson, B., et al. 2015. "Methane Emissions from the Natural Gas Transmission and Storage System in the United States." *Environmental Science & Technology* 49 (15): 9374–83. https://doi.org/10.1021/acs.est.5b01669.

25 Stokes et al. 2022.

26 Tullos et al. 2021.

27 Wang, J.L., Daniels, W.S., Hammerling, D.M., Harrison, M., Burmaster, K., George, F.C., and Ravikumar, A.P. 2022. "Multiscale Methane Measurements at Oil and natural gas Facilities Reveal Necessary Frameworks for Improved Emissions Accounting." *Environmental Science & Technology* 56, 20, 14743–14752. https://doi.org/10.1021/acs.est.2c06211.

28 Brandt et al. 2015.

29 Zimmerle, D., Vaughn, T., Luck, B., Lauderdale, T., Keen, K., Harrison, M., Marchese, A. et al. 2020. "Methane Emissions from Gathering Compressor Stations in the U.S." *Environmental Science & Technology* 54 (12): 7552–61. https://doi.org/10.1021/acs.est.0c00516.

II. PURPOSES OF METHANE EMISSIONS DETECTION AND QUANTIFICATION

The best approaches to use for methane emissions detection and quantification depend on both the characteristics of the emissions and the purpose of the emissions measurement. The original purpose of methane sensing technologies was to detect and repair methane leaks along the natural gas supply chain. Methane sensing purpose and practice, as described in 40 CFR 60 Subpart OOOOa, was originally purely qualitative, a direct outgrowth of volatile organic compound emissions controls of 40 CFR 60 Subpart OOOO. These regulations did not call for direct quantitative emissions measurements.

Over the last decade, methane sensing has become more quantitative and has developed into a credible method for constructing GHG emissions inventories.[30] There is now an impressive variety of measurement technologies. Sensors are deployed on vehicles, drones, helicopters, fixed-wing aircraft, and high-altitude platform systems. Continuous monitoring is helping to characterize the intermittency and duration of emissions. Satellite methods have extended measurements to much of the land surface of the earth.[31] This range of technologies is necessary to understand the full extent of methane emissions, with sources ranging from a single valve to a producing basin. The following sections describe how emissions detection and quantification methods are now being applied in a variety of emissions reporting and reduction activities.

A. Emissions Reporting

1. U.S. Emissions Regulatory Reporting

The Greenhouse Gas Reporting Program (GHGRP) collects quantitative emissions reports and data from facilities, by operator. U.S. GHGRP data have been collected since 2010, as specified by 40 CFR 98 Subpart W. Facilities that emit GHG emissions below a specific threshold do not have to report; the definition of facility varies between supply chain sectors and is not the same as the definition of a site (40 CFR 98.238). For example, a facility may consist of all the production sites in a production region for an operator. The GHGRP provides extensive data on routine emissions and some anticipated, unintended, and low-emissions-rate sources of emissions (the three blue quadrants in Figure 3-1). Only limited data are available for unintended high-emissions-rate sources (orange quadrant in Figure 3-1). For emissions reporting to be accurate, all types of emissions need to be accurately reported.

Emissions reporting through the GHGRP will be used in determining methane emissions fees due under the Inflation Reduction Act (Public Law 117-169). A "Waste Emissions Charge" was introduced into the Inflation Reduction Act of 2022 and is now a provision of the U.S. Code (https://www.law.cornell.edu/uscode/text/42/7436 paragraph (c)). This charge is to be paid by oil and natural gas facility operators that exceed levels of methane emissions, as defined in the Act. The Inflation Reduction Act of 2022 also mandated a potentially important change to emissions reporting through the GHGRP. After 2024, reporting must be "accurate" and based on "empirical data" (Clean Air Act, Sec. 136(h)). In response, the EPA has proposed multiple new source-level measurements. The EPA has also proposed a new emissions category of large emissions events,[32] that may increase reporting of unintended high-emissions-rate sources.

Emissions reporting has historically relied on activity data and emissions factors. As described in Section I of this chapter, emissions factors are often based on measurements made at the equipment level and can be effective for multiple categories of emissions (blue quadrants in Figure 3-1). Additional source-level emissions reporting requirements for the GHGRP have been proposed by the EPA that involve detecting large-emissions-rate sources (>100 kg/hr) using instantaneous emissions rate measurements. In reporting, a total amount of methane emitted, not an emissions rate, needs to be estimated and reported. Total emissions are estimated from measured

30 Alvarez et al. 2018.

31 Worden, J., Cusworth, D., Qu, Z., Yin, Y., Zhang, Y., Bloom, A., Ma, S., et al. 2022. "The 2019 Methane Budget and Uncertainties at 1° Resolution and Each Country through Bayesian Integration of GOSAT Total Column Methane Data and a Priori Inventory Estimates." *Atmospheric Chemistry and Physics* 22 (10): 6811–41. https://doi.org/10.5194/acp-22-6811-2022.

32 EPA. 2023.

instantaneous emissions rates using knowledge of the duration of the event, which may vary from seconds to days or longer, and the variability in emissions rates during the event. Estimating total quantities emitted during an emissions event will frequently require multiple types of measurement data.

Data from the GHGRP are also used by the EPA to inform the development of the Inventory of U.S. Greenhouse Gas Emissions and Sinks (often abbreviated GHGI, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks). As an Annex 1 nation, the United States submits this report annually to the secretariat of the United Nations Framework Convention on Climate Change (UNFCCC) (https://unfccc.int/ghg-inventories-annex-i-parties/2023). The inventory has been reported annually since 1997 (https://www.epa.gov/ghgemissions/us-greenhouse-gas-inventory-report-archive). Each annual inventory reports emissions from 1990 to two years prior to the report date. The entire time series back to 1990 is recomputed every year using the latest methodology.

In addition to national GHG emissions reporting, multiple states have implemented reporting programs that differ from national requirements, notably California, Colorado (Colorado Department of Public Health and Environment, Air Quality Control Commission 2019), and New Mexico.

2. Global Emissions Reporting

In addition to playing a role in domestic emissions reporting, there has been increased use of methane emissions measurements in international initiatives. For example, the Department of Energy has launched a global Measurement, Monitoring, Reporting, and Verification (MMRV) program for GHG emissions from natural gas supply chains.[33, 34] One of the underlying technical principles of the MMRV program is to "value measured data over modeled data."[35]

The International Energy Agency (IEA) provides an inventory of methane emissions on a global scale through the Global Methane Tracker.[36] Data on emissions are obtained from multiple sources, including the U.S. Greenhouse Gas Inventory[37] with an emphasis on providing consistent, accurate, and timely energy data and statistics.

The Oil & Gas Methane Partnership 2.0 (OGMP 2.0) is the United Nations Environment Programme's oil and natural gas reporting program.[38] Oil and natural gas companies and national oil companies that participate in OGMP report emissions at different levels of detail. The reports are reviewed by the United Nations, and organizations make a commitment to increase the level of detail in their reporting over a three- to five-year period. The highest levels of reporting (levels 4 and 5) require monitoring and reporting of source- and site-specific emissions and verification of reported emissions with independent measurements, collectively referred to as monitoring, reporting, and verification. Currently, the collection of OGMP member assets represent >37% of global oil and natural gas production when considering both the operated assets of the members and non-operated joint ventures for which OGMP members have financial interest.[39] Only aggregated data, by organization, are publicly reported.

3. Trade Association and Reporting Initiatives

Companies have made voluntary GHG emissions and reduction commitments. Examples of

33 DOE. "Greenhouse Gas Supply Chain Emissions Measurement, Monitoring, Reporting, Verification Framework." Last updated March 15, 2024. https://www.energy.gov/fecm/greenhouse-gas-supply-chain-emissions-measurement-monitoring-reporting-verification-framework.

34 DOE. "DOE Announces Global Collaboration to Reduce Methane Emissions." November 15, 2023. https://www.energy.gov/fecm/articles/doe-announces-global-collaboration-reduce-methane-emissions.

35 DOE. "Informational Webinar: International Greenhouse Gas Supply Chain Emissions Measurement, Monitoring, Reporting, Working Group." September 15, 2023. https://www.energy.gov/fecm/events/informational-webinar-international-greenhouse-gas-supply-chain-emissions-measurement.

36 IEA. "Methane Tracker Database." Last updated March 2024. https://iea.org/data-and-statistics/data-product/methane-tracker-database-2023.

37 EPA. 2023.

38 UNEP. 2024. "The Oil & Gas Methane Partnership 2.0 (OGMP 2.0)." https://www.unep.org/explore-topics/energy/what-we-do/methane/oil-gas-methane-partnership-20-ogmp-20.

39 UNEP. 2023. "An eye on methane: The road to radical transparency." https://wedocs.unep.org/bitstream/handle/20.500.11822/44129/eye_on_methane.pdf?sequence=3.

the commitments include the American Petroleum Institute, The Environmental Partnership (https://theenvironmentalpartnership.org/), ONE Future's 1% Emission's Intensity (https://onefuture.us/), and the Edison Electric Institute/American Gas Association Natural Gas Sustainability Initiative (https://www.eei.org/en/issues-and-policy/ngsi). The commitments include annual reports to demonstrate progress in the achievement of the goals. Companies plan to use technology to detect and quantify their emissions to drive continuous reductions.

4. Greenhouse Gas Certifications

Methane emissions associated with natural gas supply chains have become an important issue among many end users, both domestically and internationally. For example, Japan and the European Union are developing methane emissions reporting standards for imported liquefied natural gas (LNG). Domestically, there are multiple voluntary certification protocols.[40] Some only focus on upstream emissions associated with production and others attempt to encompass the entire supply chain. Certification programs are described in more detail in Chapter 1.

5. Input to Trade Preference Mechanisms

In addition to domestic emissions reporting, systems for international trade in natural gas that require reporting of emissions are beginning to emerge. For example, the European Union (EU) has proposed collecting methane emissions data from nations exporting oil and natural gas received by the EU. According to the preamble of a European Commission legislative proposal, the "framework should contain rules to enhance transparency with regard to fossil energy imports into the Union, thus improving the incentives for a wider uptake of methane mitigation solutions across the globe."[41, 42]

B. Emissions Reduction Activities

1. Leak Detection and Repair

One of the most mature, yet still evolving, methods to detect losses from the oil and natural gas supply chains is leak detection and repair, commonly referred to as LDAR. The EPA and state agencies have promulgated regulations applying to oil and natural gas companies that address LDAR survey frequency, types of facilities that are required to follow LDAR regulations, required training for leak detection technicians, maintenance protocols, and required data storage and reporting. Current regulations address leakage and repair for methane and volatile organic compounds.

LDAR regulations are narrowly focused on detection of unintended emissions sources. The largest number of emitters identified by these regulations are relatively small leaks that persist continuously over months (lower right quadrant in Figure 3-1), although some rare large leaks are also detected (upper right quadrant in Figure 3-1).[43, 44, 45] Most LDAR programs require measurement surveys for emissions detection a few times a year (40 CFR 60 subpart OOOOa). This type of measurement is appropriate only for emissions sources that have durations commensurate with sampling intervals. Large,

40 Highwood Emissions Management. 2022. "Voluntary Emissions Reduction Initiatives." https://highwoodemissions.com/reports/voluntary-emissions-reduction-initiative-2022/.

41 Council of the European Union. "Climate Action: Council and Parliament reach deal on new rules to cut methane emissions in the energy sector." November 15, 2023. https://www.consilium.europa.eu/en/press/press-releases/2023/11/15/climate-action-council-and-parliament-reach-deal-on-new-rules-to-cut-methane-emissions-in-the-energy-sector/.

42 Council of the European Union. "Climate Action: Council and Parliament reach deal on new rules to cut methane emissions in the energy sector." November 15, 2023. https://www.consilium.europa.eu/en/press/press-releases/2023/11/15/climate-action-council-and-parliament-reach-deal-on-new-rules-to-cut-methane-emissions-in-the-energy-sector/.

43 Brandt et al. 2015.

44 Vaughn, T., Bell, C., Yacovitch, T., Roscioli, J., Herndon, S., Conley, S., Schwietzke, S., Heath, G., Pétron, G., and Zimmerle, D. 2017. "Comparing Facility-Level Methane Emission Rate Estimates at Natural Gas Gathering and Boosting Stations." *Elementa: Science of the Anthropocene* 5 (0): 71. https://doi.org/10.1525/elementa.257.

45 Zimmerle et al. 2020.

unintended releases (upper right quadrant in Figure 3-1) are often infrequent, intermittent, and of variable duration[46] and are unlikely to be found using detection methods designed for emissions that are frequent or of relatively long duration.

In recent regulations, the EPA has described a process for substituting current emissions detection technologies with alternative measurement methods.[47] The process for demonstrating equivalency is based on the detection efficiency, detection limits, and quantification capabilities of the technology.

46 European Commission. 2021. "Proposal for a Regulation of the European Parliament and of the Council on methane emissions reduction in the energy sector and amending Regulation (EU) 2019/942." EPA-HQ-OAR-2021-0317-2336_attachment_1.pdf.

47 EPA. 2024. "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." https://www.federalregister.gov/documents/2024/03/08/2024-00366/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for.

FINDING 3: **A variety of regulatory and voluntary initiatives are driving the collection of measurements of methane emissions; the spatial and temporal scale of the information required by these initiatives can range from individual sources to basin levels and from instantaneous emissions rates to annual emissions totals.**

III. EMISSIONS DETECTION AND QUANTIFICATION SYSTEMS

Methods of detecting and quantifying methane emissions are deployed at multiple spatial and temporal scales, ranging from technologies used for individual sources over short periods to technologies applied at regional or global scales over extended periods, as shown in Figure 3-2.

When measurement methods are applied at very large scales, a single measurement includes many emissions sources and sites. Measurement methods are also applied at the scale of individual emissions sources, often a single piece of equipment, and then scaled to larger numbers of

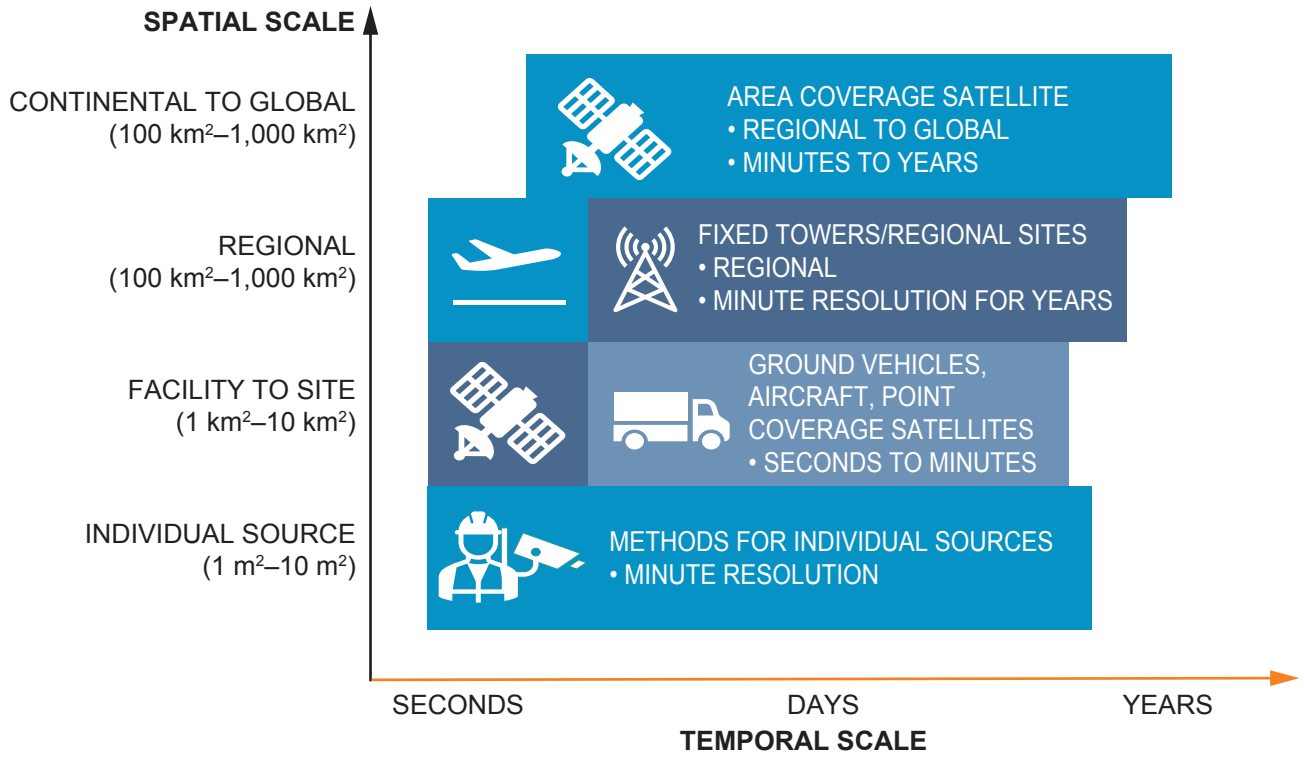


Figure 3-2. *Measurement Technologies Operate at a Variety of Spatial and Temporal Scales*

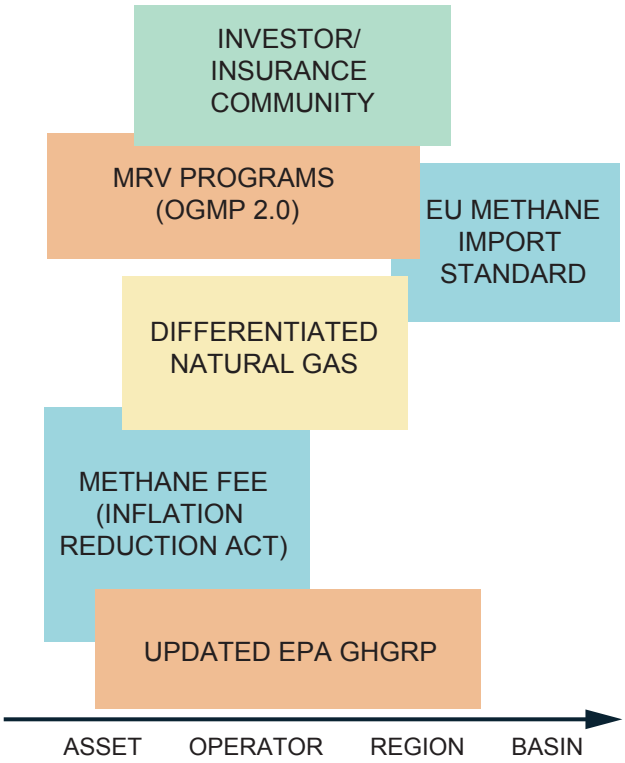


Figure 3-3. *Spatial Scales at which Measurement Information Is Needed Varies with the Purpose of the Measurement*

sources using equipment counts and activity data and measurements for each type of activity. Each scale of measurement has advantages and disadvantages. Equipment-level measurements provide detailed information about individual sources and the types of equipment and operations that emit. This approach guides actions to reduce emissions, but may miss some unexpected, unintended, or uncharacterized emissions sources. Larger scale measurements generally lack detail about individual sources but can provide information about total emissions at a site, a facility, or in a region.

Methods for detecting, measuring, and quantifying emissions also vary in their duration. Some methods provide a single 'snapshot' of methane emissions; others are recurring or make measurements continuously. The best choice for temporal coverage of measurements will depend on the characteristics of emissions sources at a facility, the cost effectiveness of the methods, and the purposes of the measurement. Generally, there is no single technology that will meet all measurement needs.

The spatial scales at which measurement information is needed also varies with the purpose of the measurement, as shown in Figure 3-3. For example, emissions reporting through the GHGRP is reported by operators, by region for production and gathering, and by site for transmission and storage. Methane fees are expected to be assessed based on GHGRP reporting and information at the asset and operator level. Other programs have information needs that span different spatial scales, as described in Section II.

A. Classification of Emissions Estimation Methods

1. Top-Down and Bottom-Up Estimates

Measurements or estimates of methane emissions are commonly described as either bottom-up or top-down.[48, 49, 50, 51, 52] Definitions for these terms vary, with relatively little consistency in scientific literature. The terms are sometimes used as synonyms for ground-based versus aircraft or satellite measurements, respectively.

48 Allen, David T. 2014. "Methane Emissions from Natural Gas Production and Use: Reconciling Bottom-up and Top-down Measurements." *Current Opinion in Chemical Engineering* 5 (August): 78–83. https://doi.org/10.1016/j.coche.2014.05.004.

49 Vaughn, T., Bell, C., Pickering, C., Schwietzke, S., Heath, G., Pétron, G., Zimmerle, D., Schnell, R., and Nummedal, D. 2018. "Temporal Variability Largely Explains Top-Down/Bottom-up Difference in Methane Emission Estimates from a Natural Gas Production Region." Proceedings of the National Academy of Sciences 115 (46): 11712–17. https://doi.org/10.1073/pnas.1805687115.

50 Pétron, G., Karion, A., Sweeney, C., Miller, B., Montzka, S., Frost, G., Trainer, M., et al. 2014. "A New Look at Methane and Nonmethane Hydrocarbon Emissions from Oil and Natural Gas Operations in the Colorado Denver-Julesburg Basin." *Journal of Geophysical Research: Atmospheres* 119 (11): 6836–52. https://doi.org/10.1002/2013jd021272.

51 Karion, A., Sweeney, C., Kort, E., Shepson, P., Brewer, A., Cambaliza, M., Conley, S., et al. 2015. "Aircraft-Based Estimate of Total Methane Emissions from the Barnett Shale Region." *Environmental Science & Technology* 49 (13): 8124–31. https://doi.org/10.1021/acs.est.5b00217.

52 Peischl, J., Ryerson, T., Aikin, K., de Gouw, J., Gilman, J., Holloway, J., Lerner, B., et al. 2015. "Quantifying Atmospheric Methane Emissions from the Haynesville, Fayetteville, and Northeastern Marcellus Shale Gas Production Regions." *Journal of Geophysical Research: Atmospheres* 120 (5): 2119–39. https://doi.org/10.1002/2014jd022697.

Other usages[53] apply the term *bottom-up* to describe accounting-style emissions estimates for a specific asset or asset type, employing equipment counts, activity data, and emissions factors. Within this definition, bottom-up measurements can be performed by any technique that can measure emissions rate for an individual source. Technologies used can be handheld cameras, fixed or mobile point sensors located at or near the fence line, or aircraft or satellites capable of imaging emissions plumes and connecting them to specific assets. Emissions factors used in bottom-up estimates may be based on measurements of operating equipment but can also be based on engineering calculations or laboratory-based measurements under controlled conditions.

Top-down, or the related but not identical term of *atmospheric* estimates,[54] generally refer to emissions estimates based on measurements of the concentration of methane in the atmosphere. The focus is not generally on individual sites but on countries, oil- and gas-producing regions, or large grid cells tens to hundreds of kilometers in extent. These measurements may be made on the ground with towers,[55] by aircraft,[56, 57] or by satellites.[58]

Some measurements from aircraft and satellites may be thought of as bottom-up if they detect and estimate methane plumes from individual facilities or equipment units on those facilities. These measurements utilize the same data used for top-down atmospheric measurements, but the data are processed differently.[59, 60]

Because of the variability in definitions in use for top-down and bottom-up emissions estimates, this report will limit the use of these terms. When used, the term bottom-up emissions estimates refers to estimates applied to an inventory of equipment and activities, whether on an emissions factor basis, direct source-level measurements, or a combination of approaches. When used, top-down measurements will refer to estimates of emissions at a site or system level (equipment groups, site, multiple sites, or regional) that do not rely on an inventory of equipment and are generally performed remotely from the system.

2. Scale of Emissions Estimates: Source, Site, and Basin Levels

Different emissions measurement approaches have varying spatial resolution and are applied at varying spatial scales, as shown in Figure 3-2. Some technologies are suited for individual equipment units[61] and others for whole facilities or geographic areas encompassing many facilities. Estimates can typically be categorized as either source level, site level, or basin level/regional level, depending on their spatial scale.

Source-level measurements quantify emissions from individual emissions locations where gas is released into the atmosphere; these methods may be methane specific or may measure composite hydrocarbon emissions, called whole gas or field gas. The location of that emissions point is typically known or can be detected with some type of sensor, and the source-level

53 Allen. 2014.

54 Brandt, A., Heath, G., Kort, E., O'Sullivan, F., Petron, G., Jordaan, S., Tans, P., et al. 2014. "Methane Leaks from North American Natural Gas Systems." *Science* 343 (6172): 733–35. https://doi.org/10.1126/science.1247045.

55 Barkley, Z., Davis, K., Miles, N., Richardson, S., Deng, A., Hmiel, B., Lyon, D., and Lauvaux, T. 2023. "Quantification of oil and gas methane emissions in the Delaware and Marcellus Basins Using a Network of Continuous Tower-Based Measurements." *Atmospheric Chemistry and Physics* 23, 6127–6144. https://doi.org/10.5194/acp-23-6127-2023.

56 Vaughn et al. 2018.

57 Kunkel, W., Carre-Burritt, A., Aivazian, G., Snow, N., Harris, J., Mueller, T., Roos, P., and Thorpe, M. 2023. "Extension of Methane Emission Rate Distribution for Permian Basin Oil and Gas Production Infrastructure by Aerial LiDAR." *Environmental Science & Technology* 57 (33): 12234–41. https://doi.org/10.1021/acs.est.3c00229.

58 Jacob, D., Varon, D, Cusworth, D., Dennison, P., Frankenberg, C., Gautam, R., Guanter, L., et al. 2022. "Quantifying Methane Emissions from the Global Scale Down to Point Sources Using Satellite Observations of Atmospheric Methane. *Atmospheric Chemistry and Physics* 22, 9617–9646. https://doi.org/10.5194/acp-22-9617-2022.

59 Conrad, B., Tyner, D., and Johnson, M. 2023. "Robust Probabilities of Detection and Quantification Uncertainty for Aerial Methane Detection: Examples for Three Airborne Technologies." *Remote Sensing of Environment* 288 (April): 113499–99. https://doi.org/10.1016/j.rse.2023.113499.

60 Vaughn et al. 2017.

61 An equipment unit is defined as in Zimmerle et al., 2019 as a unit of major equipment connected to a facility through a small set of well-defined connection points. Examples include compressors, dehydrators, tanks, separators, and flares.

measurement technology can be selected based on the physical characteristics of the identified source. Examples of source-level measurements include flow meters on vented sources,[62, 63, 64] stack tests performed on combustion equipment,[65, 66, 67] and handheld devices that can detect, locate, and quantify emissions from a single fugitive or vented location.[68, 69, 70, 71, 72] Source-level measurements are typically made at an emissions point that can be isolated as a single emissions source. A chief advantage of source-level measurements is that they can be designed for the targeted emissions source, enabling measurements with greater accuracy and lower levels of uncertainty.

Site-level estimates quantify methane emissions from an entire site. A site is typically a pad or some other discrete, well-defined area, however, in some parts of the supply chain, precisely defining a site can be difficult. By definition, a site-level estimate provides an aggregated estimate of all methane released into the atmosphere from a site, and therefore does not require that each emissions source be detected before measurement. To support this site-level operational mode, these methods *measure* atmospheric concentrations of methane (or occasionally whole gas), and then *estimate* emissions using meteorological data and some type of model describing the transport or dispersion of emissions from the source to the location of the measurement. The estimated methane emissions from a site should therefore include all sources at the site, provided the method is both robust and complete.

Basin-level estimates quantify methane emissions from an entire production basin or a similar, typically compact, grouping of facilities.[73, 74, 75] Similar methods may also be used to assess emissions from regions, including cities[76, 77] or

62 Allen et al. 2015a.

63 Allen et al. 2015.

64 Luck, B., Zimmerle, D., Vaughn, T., Lauderdale, T., Keen, K., Harrison, M., Marchese, A., et al. 2019. "Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations." *Environmental Science & Technology Letters* 6 (6): 348–52. https://doi.org/10.1021/acs.estlett.9b00158.

65 Vaughn, T., Luck, B., Williams, L., Marchese, A., and Zimmerle, D. 2021. "Methane Exhaust Measurements at Gathering Compressor Stations in the United States." *Environmental Science & Technology* 55 (2): 1190–96. https://doi.org/10.1021/acs.est.0c05492.

66 Johnson, M., Devillers, R., and Thomson, K. 2010. "Quantitative Field Measurement of Soot Emission from a Large Gas Flare Using Sky-LOSA." *Environmental Science & Technology* 45 (1): 345–50. https://doi.org/10.1021/es102230y.

67 Johnson, D., Covington, A., and Clark, N. 2015. "Methane Emissions from Leak and Loss Audits of Natural Gas Compressor Stations and Storage Facilities." *Environmental Science & Technology* 49 (13): 8132–38. https://doi.org/10.1021/es506163m.

68 Allen, D., Torres, V., Thomas, J., Sullivan, D., Harrison, M., Hendler, A., Herndon, S., et al. 2013. "Measurements of Methane Emissions at Natural Gas Production Sites in the United States." *Proceedings of the National Academy of Sciences* 110 (44): 17768–73. https://doi.org/10.1073/pnas.1304880110.

69 Zimmerle, D., Vaughn, T., Bell, C., Bennett, K., Deshmukh, P., and Thoma, E. 2020. "Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions." *Environmental Science & Technology* 54 (18): 11506–14. https://doi.org/10.1021/acs.est.0c01285.

70 Johnson, D., Covington, A., and Clark, N. 2015. "Methane Emissions from Leak and Loss Audits of Natural Gas Compressor Stations and Storage Facilities." *Environmental Science & Technology* 49 (13): 8132–38. https://doi.org/10.1021/es506163m.

71 Festa-Bianchet, S., Milani, Z., and Johnson, M. 2023. "Methane Venting from Uncontrolled Production Storage Tanks at Conventional Oil Wells—Temporal Variability, Root Causes, and Implications for Measurement." *Elementa* 11 (1). https://doi.org/10.1525/elementa.2023.00053.

72 Zimmerle, D., Vaughn, T., Bennett, K., Ross, C., Harrison, M., Wilson, A., and Johnson, C. "Open-Source High Flow Sampler for Natural Gas Leak Quantification." Prepared for the California Air Resources Board. April 14, 2022. https://mountainscholar.org/handle/10217/235420.

73 Pétron, G., Karion, A., Sweeney, C., Miller, B, Montzka, S., Frost, G., and Trainer, M., et al. 2014. "A new look at methane and nonmethane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver Julesburg Basin." *Journal of Geophysical Research: Atmospheres* 119: 6836 - 6852. https://doi.org/10.1002/2013JD021272.

74 Peischl et al. 2015.

75 Schwietzke, S., Pétron, G., Conley, S., Pickering, C., Mielke-Maday, I., Dlugokencky, E., Tans, P., et al. 2017. "Improved Mechanistic Understanding of Natural Gas Methane Emissions from Spatially Resolved Aircraft Measurements." *Environmental Science & Technology* 51 (12): 7286–94. https://doi.org/10.1021/acs.est.7b01810.

76 Davis, K., Deng, A., Lauvaux, T., Miles, N., Richardson, S., Sarmiento, D., Gurney, K., et al. 2017. "The Indianapolis Flux Experiment (INFLUX): A Test-Bed for Developing Urban Greenhouse Gas Emission Measurements." *Elementa: Science of the Anthropocene* 5 (0): 21. https://doi.org/10.1525/elementa.188.

77 Peischl, S., Dupanloup, I., Kirkpatrick, M., and Excoffier, L. 2013. "On the Accumulation of Deleterious Mutations during Range Expansions." *Molecular Ecology* 22 (24): 5972–82. https://doi.org/10.1111/mec.12524.

countries. Three general methods are utilized for basin-level estimates:

1. Scaling site estimates (plumes): One method scales from individual plume estimates to basin level by summing plumes, typically weighted by some measure of persistence[78] and/or by scaling based upon a stratified inventory of site types.[79, 80] These methods extend results from site-level measurements by 'filling in' necessary details to scale to basin level.

2. Regional inversions: A second method estimates basin-level emissions by measuring concentrations in the atmosphere and using meteorological data and emissions transport models to translate concentrations into an estimate of basin emissions. These methods are often called inversions, referring to the inverse process of inferring emissions sources from downwind concentration data. Some methods utilize satellite column-integrated methane concentrations and inversion models to both estimate total methane emissions and to attribute those emissions to source types.[81, 82] Other methods utilize towers located around the basin, coupled with Bayesian inversion methods to estimate emissions.[83, 84, 85] Since the region over which inversions are performed may contain sources not related to oil and natural gas operations, these regional methods also need to account for non-oil and natural gas sources.

3. Mass balance flights: Finally, a third method utilizes aircraft flights upwind and downwind of a region to estimate incremental methane flux generated inside the region. This method has been utilized extensively in basins and cities across the United States.[86, 87, 88, 89, 90, 91]

Each level of measurement has strengths and weaknesses.

Source-level measurements provide direct, actionable information by identifying and quantifying specific sources. However, source-level measurements have been criticized for not identifying all methane emissions sources, and for missing some large or intermittent sources.[92] To conduct source-level measurements, an

78 Cusworth, D., Duren, R., Yadav, V., Thorpe, A., Verhulst, K., Sander, S., Hopkins, F., et al. 2020. "Synthesis of Methane Observations across Scales: Strategies for Deploying a Multi-tiered Observing Network." *Geophysical Research Letters* 47 (7). https://doi.org/10.1029/2020gl087869.

79 Sherwin, E., Rutherford, J., Zhang, Z., Chen, Y., Wetherley, E., Yakovlev, P., Berman, E., et al. 2023. "Quantifying Oil and Natural Gas System Emissions Using One Million Aerial Site Measurements." *Nature* 627, 328-334. https://www.nature.com/articles/s41586-024-07117-5.

80 Lyon, D., Zavala-Araiza, D., Alvarez, R., Harriss, R., Palacios, V., Lan, X., Talbot, R., et al. 2015. "Constructing a Spatially Resolved Methane Emission Inventory for the Barnett Shale Region." *Environmental Science & Technology* 49 (13): 8147–57. https://doi.org/10.1021/es506359c.

81 Varon, D., Jacob, D., McKeever, J., Jervis, D., Durak, B., Xia, Y., and Huang, Y. 2018. "Quantifying Methane Point Sources from Fine-Scale Satellite Observations of Atmospheric Methane Plumes." *Atmospheric Measurement Techniques* 11 (10): 5673–86. https://doi.org/10.5194/amt-11-5673-2018.

82 Cui, Y., Vijayan, A., Falk, M., Hsu, Y., Yin, D., Chen, X., Zhao, Z., et al. 2019. "A Multiplatform Inversion Estimation of Statewide and Regional Methane Emissions in California during 2014–2016." *Environmental Science & Technology* 53 (16): 9636–45. https://doi.org/10.1021/acs.est.9b01769.

83 Barkley, Z., Lauvaux, T., Davis, K., Deng, A., Fried, A., Weibring, P., Richter, D., et al. 2019. "Estimating Methane Emissions from Underground Coal and Natural Gas Production in Southwestern Pennsylvania." *Geophysical Research Letters* 46 (8): 4531–40. https://doi.org/10.1029/2019gl082131.

84 Barkley, Z., Lauvaux, T., Davis, K., Deng, A., Miles, N., Richardson, S., Cao, Y., et al. 2017. "Quantifying Methane Emissions from Natural Gas Production in North-Eastern Pennsylvania." *Atmospheric Chemistry and Physics* 17 (22): 13941–66. https://doi.org/10.5194/acp-17-13941-2017.

85 Miles, N., Richardson, S., Lauvaux, T., Davis, K., Balashov, N., Deng, A., Turnbull, J., et al. 2017. "Quantification of Urban Atmospheric Boundary Layer Greenhouse Gas Dry Mole Fraction Enhancements in the Dormant Season: Results from the Indianapolis Flux Experiment (INFLUX)." *Elementa: Science of the Anthropocene* 5 (0): 27. https://doi.org/10.1525/elementa.127.

86 Pétron, G., Karion, A., Sweeney, C., Miller, B, Montzka, S., Frost, G., Trainer, M., et al. 2014. "A New Look at Methane and Nonmethane Hydrocarbon Emissions from Oil and Natural Gas Operations in the Colorado Denver-Julesburg Basin." *Journal of Geophysical Research-Atmospheres* 119 (11): 6836-6852. https://doi.org/10.1002/2013JD021272.

87 Karion et al. 2015.

88 Schwietzke et al. 2017.

89 Vaughn et al. 2017.

90 Conley, S., Franco, G., Faloona, I., Blake, D., Peischl, J., and Ryerson, T. 2016. "Methane Emissions from the 2015 Aliso Canyon Blowout in Los Angeles, CA." *Science* 351 (6279): 1317–20. https://doi.org/10.1126/science.aaf2348.

91 Lyon et al. 2015.

92 Zimmerle et al. 2020.

understanding of the location of possible sources is required. If an emissions source is unknown, then an operator may not detect the source, or may not have appropriate technology to measure a source. Therefore, though source-level measurements are an important tool, these methods have been criticized for (a) not detecting and measuring all sources; and (b) having insufficient sample size to capture large, rare events, which may contribute a significant fraction of total emissions.[93, 94, 95]

Additionally, source-level measurement has historically served as the basis for GHG emissions reporting for both regulatory[96] and voluntary programs (e.g., Oil & Gas Methane Partnership (OGMP)). Many regulatory programs specify specific lists of sources that must be screened for emissions and which sources must be measured, calculated, or estimated with emissions factors. As a result, many source-level screening and measurement programs look only at a subset of sources, which may reduce the accuracy of using source-level measurements.

Site-level estimates are based on observations for a location. Therefore, individual sources need not be detected and/or known. Additionally, technologies that provide continuous, or near continuous, monitoring of facilities may provide updates on on-site emissions at a far higher frequency (minutes to hours) than typical survey methods (revisits spaced months apart). If measurements are made at low frequency, site-level measurements may not capture large, rare events or capture the entire duration of an emissions event, based on the same reasoning as applied to source measurements. Additional fundamental challenges to site-level estimates make it difficult to rely on them in the place of source-level measurements, or to replace bottom-up inventory estimates.

First, site-level estimates frequently cannot localize emissions to a specific source. If there is a discrepancy between a site-level estimate and a sum of source-level measurements, it is often impossible to identify what is causing the discrepancy, particularly for complex sites.[97]

Second, most site-level estimates measure atmospheric methane concentration at a sufficient distance from the site for methane emissions to develop into a plume[98, 99] or to become sufficiently well mixed in the atmosphere that short-term fluctuations are averaged out of observations.[100, 101, 102, 103] Therefore, interpreting measurement data requires atmospheric modeling, which introduces significant modeling

93 Sherwin et al. 2023.

94 Cusworth et al. 2020.

95 Peischl et al. 2015.

96 EPA. 2014. "Greenhouse Gas Reporting Program (GHGRP)." Last updated April 4, 2024. https://www.epa.gov/ghgreporting.

97 Brown, J., Harrison, M., Rufael, T., Roman-White, S., Ross, G., George, F., and Zimmerle, D. 2023. "Informing Methane Emissions Inventories Using Facility Aerial Measurements at Midstream Natural Gas Facilities." *Environmental Science & Technology* 57 (39): 14539–47. https://doi.org/10.1021/acs.est.3c01321.

98 Shaw, J., Shah, A., Yong, H., and Allen, G. "Methods for Quantifying Methane Emissions Using Unmanned Aerial Vehicles: A Review." *Philosophical Transactions of the Royal Society A: Mathematical, Physical and Engineering Sciences A* 379: 20200450. 2021. https://doi.org/10.1098/rsta.2020.0450.

99 Thorpe, A., Frankenberg, C., Aubrey, A., Roberts, D., Nottrott, A., Rahn, T., Sauer, J., et al. "Mapping Methane Concentrations from a Controlled Release Experiment Using the Next Generation Airborne Visible/Infrared Imaging Spectrometer (AVIRIS-NG)." *Remote Sensing of Environment* 179 (June): 104–15. 2016. https://doi.org/10.1016/j.rse.2016.03.032.

100 Brantley, H., Thoma, E., Squier, W., Guven, B., and Lyon, D. 2014. "Assessment of Methane Emissions from Oil and Gas Production Pads Using Mobile Measurements." *Environmental Science & Technology* 48 (24): 14508–15. https://doi.org/10.1021/es503070q.

101 Edie, R., Robertson, A., Field, R., Soltis, J., Snare, D., Zimmerle, D., Bell, C., et al. 2020. "Constraining the Accuracy of Flux Estimates Using OTM 33A," *Atmospheric Measurement Techniques* 13, 341-353 https://doi.org/10.5194/amt-2019-306.

102 Roscioli, J., Yacovitch, T., Floerchinger, C., Mitchell, A., Tkacik, D., Subramanian, R., Martinez, D., et al. 2015. "Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Methods." *Atmospheric Measurement Techniques* 8 (5): 2017–35. https://doi.org/10.5194/amt-8-2017-2015.

103 Lamb, B., McManus, J., Shorter, J., Kolb, C., Mosher, B., Harriss, R., Allwine, E., et al. 1995. "Development of Atmospheric Tracer Methods to Measure Methane Emissions from Natural Gas Facilities and Urban Areas." *Environmental Science & Technology* 29 (6): 1468–79. https://doi.org/10.1021/es00006a007.

uncertainty.[104, 105, 106, 107] Site-level estimates can have significantly greater uncertainty ranges than source-level measurements. Recent work indicates these estimates may also have bias in mean estimates, indicating that repeat measurements will not produce an average estimate of emissions that converges to the true total emissions.[108, 109, 110, 111]

Basin-level estimates that scale from site-level (typically 'plumes') measurements are a logical use of wide-area, site-level sampling strategies, such as those performed in numerous basins across the United States.[112, 113, 114, 115, 116] This type of scaling has the same measurement constraints as the site-level measurements on which they are based. For this use, it is critically important that site-level estimates used in scaling are unbiased in the mean. Additionally, these estimates rely on assumptions for scaling to basin level that may introduce additional uncertainty into these estimates.[117]

Basin-level estimates developed directly from atmospheric methane concentrations (typically from satellites or aircraft) are largely independent of other estimation methods. Additionally, the underlying concentration measurements require no knowledge of underlying emissions sources. However, the regional inversion methods for estimating methane flux from methane concentration must assume a spatial distribution, and an expected temporal variability, of sources in the region of interest. Spatial distribution is often derived from annual or monthly inventory estimates, most populated from prior source-level estimates in the form of activity and emissions factors. Most methods assume little-to-no diurnal or weekly variability in the initial estimate of emissions, even though certain activities, such as those that require operator involvement (e.g., blowdowns) have strong diurnal and day-of-week variability; other emissions sources have variability introduced by temperatures. Aircraft and satellite measurements occur almost exclusively during daylight hours and may be restricted in their seasonal deployment, and so only sample a subset of diurnal and other time-varying activities.[118, 119, 120] The inversion process, meteorological inputs, and assumptions in the prior estimate of emissions all introduce additional uncertainty into basin-level estimates.

104 Corbett, Abigail, and Brendan Smith. 2022. "A Study of a Miniature TDLAS System Onboard Two Unmanned Aircraft to Independently Quantify Methane Emissions from Oil and Gas Production Assets and Other Industrial Emitters." *Atmosphere* 13 (5): 804. https://doi.org/10.3390/atmos13050804.

105 Bell, C., Rutherford, J., Brandt, A., Sherwin, E., Vaughn, T., and Zimmerle, D. 2022. "Single-Blind Determination of Methane Detection Limits and Quantification Accuracy Using Aircraft-Based LiDAR." *Elementa: Science of the Anthropocene* 10 (1). https://doi.org/10.1525/elementa.2022.00080.

106 Conrad et al. 2023.

107 Sherwin, E., Chen, Y., Ravikumar, A., and Brandt, A. 2021. "Single-Blind Test of Airplane-Based Hyperspectral Methane Detection via Controlled Releases." *Elementa: Science of the Anthropocene* 9 (1). https://doi.org/10.1525/elementa.2021.00063.

108 Brown et al. 2023.

109 Bell, Clay., Vaughn, T., Zimmerle, D., Herndon, S., Yacovitch, T., Heath, G., Pétron, G., et al. 2017. "Comparison of Methane Emission Estimates from Multiple Measurement Techniques at Natural Gas Production Pads." *Elementa: Science of the Anthropocene* 5 (0): 79. https://doi.org/10.1525/elementa.266.

110 Ilonze, C., Emerson, E., Duggan, A., and Zimmerle, D. 2024. "Assessing the Progress of the Performance of Continuous Emission Monitoring Solutions under Single-Blind Controlled Testing Protocol." Preprint. https://chemrxiv.org/engage/chemrxiv/article-details/65298bd3bda59ceb9a869920.

111 Brown, J., Harrison, M., Rufael, T., Roman-White, S., Ross, G., George, F., and Zimmerle, D. 2024. "Evaluating Development of Empirical Estimates Using Two Top-down Methods at Midstream Natural Gas Facilities." *Atmosphere* 15(4), 447. https://www.mdpi.com/2073-4433/15/4/447.

112 Kunkel et al. 2023.

113 Cusworth et al. 2020.

114 Lyon et al. 2015.

115 Lyon, D., Alvarez, R., Zavala-Araiza, D., Brandt, A., Jackson, R., and Hamburg, S. 2016. "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites." *Environmental Science & Technology* 50 (9): 4877–86. https://doi.org/10.1021/acs.est.6b00705.

116 Duren, R., Thorpe, A., Foster, K., Rafiq, T., Hopkins, F., Yadav, V., Bue, B., et al. "California's Methane Super-Emitters." *Nature* 575 (7781): 180–84. 2019. https://doi.org/10.1038/s41586-019-1720-3.

117 Zimmerle, D., Dileep, S., and Quinn, C. 2024. "Unaddressed Uncertainties When Scaling Regional Aircraft Emissions Surveys to Basin Emission Estimates." *Environmental Science & Technology* 58, 15, 6575-6585. https://pubs.acs.org/doi/10.1021/acs.est.3c08972.

118 Barkley et al. 2017.

119 Barkley et al. 2019.

120 Jacob, D., Varon, D., Cusworth, D., Dennison, P., Frankenberg, C., Gautam, R., Guanter, L., et al. 2022. "Quantifying Methane Emissions from the Global Scale down to Point Sources Using Satellite Observations of Atmospheric Methane." *Atmospheric Chemistry and Physics* 22 (14): 9617–46. https://doi.org/10.5194/acp-22-9617-2022.

Basin-level inversion or aircraft mass balance methods typically utilize methane-specific instruments, although some ongoing tower-based studies and aircraft mass balance flights have used instruments that measure both methane and ethane. Since basin-level emissions estimates include all sources in a region, methane emissions from oil and natural gas operations are frequently mixed with emissions from other sources such as coal mines, geological seeps, landfills, and agricultural operations involving manure handling or ruminant animals. To attribute emissions to these non-oil and natural gas sources, inversion methods must make assumptions about the location, size, and variability of underlying source types. Chemical and isotopic signatures of the emissions of specific sources can be used in this source attribution[121] and ethane is often used as a marker species for oil and natural gas emissions.[122, 123] If ethane measurements are available, source attribution methods must also assume the methane-ethane ratio of oil and natural gas sources. Methane to ethane ratios vary significantly depending on the nature of the sources in oil and natural gas supply chains. For example, methane to ethane ratios in tank flash emissions can be a factor of five or more higher than emissions associated with venting produced gas.[124] Using average methane to ethane ratios in regional source attribution requires assumptions about the relative magnitude of oil and natural gas sources with different methane to ethane ratios. These various assumptions inject uncertainty into emissions estimates.

Emissions estimates based on short-duration (e.g., minutes to hours) single measurements are difficult to extrapolate to estimate long-term (e.g., annual) emissions from sources that are temporally variable, even if the short-duration measurements are repeated. If source- and site-level measurements are conducted intermittently, then their results may not reflect the overall behavior of a source or site's methane emissions.[125] Innovative sampling strategies, including continuous source measurement[126] or structured top-down sampling[127, 128, 129, 130, 131] have been proposed to address temporal variability.

Recent work has focused on methods to integrate source-level estimates, inventory methods, and site-level estimates into a more robust estimate of emissions than can be accomplished by any one method alone. One such approach is termed "measurement-informed inventory," where periodic full-site estimates are combined with robust inventory methods to scale short-duration, full-facility estimates to long-duration estimates, such as annual emissions rates.[132] This approach underlies several recent voluntary emissions reporting approaches (e.g., Veritas 2021; MIQ n.d.; OGMP).[133]

In summary, recent research indicates that source-level, site-level, and basin-level estimation methods provide information about emissions, but all have issues that impact the accuracy and applicability of their results when used as the only source of information. When used in combination, however, they can be an efficient tool in detection of unintended emissions.

121 Allen, David. 2016. "Attributing Atmospheric Methane to Anthropogenic Emission Sources." *Accounts of Chemical Research* 49 (7): 1344–50. https://doi.org/10.1021/acs.accounts.6b00081.

122 Pétron et al. 2014b.

123 Schwietzke et al. 2017.

124 Cardoso-Saldaña, F., Pierce, K., Chen, Q., Kimura, Y., and Allen, D. 2021. "A Searchable Database for Prediction of Emission Compositions from Upstream Oil and Gas Sources." *Environmental Science & Technology* 55 (5): 3210–18. https://doi.org/10.1021/acs.est.0c05925.

125 Schissel, C., Allen, D., and Dieter, H. 2024. "Methods for Spatial Extrapolation of Methane Measurements in Constructing Regional Estimates from Sample Populations." *Environmental Science & Technology* 58,6, 2739-2749. https://doi.org/10.26434/chemrxiv-2023-zcqnq.

126 Luck et al. 2019.

127 Cusworth, D., Duren, R., Thorpe, A., Olson-Duvall, W., Heckler, J., Chapman, J., Eastwood, M., et al. "Intermittency of Large Methane Emitters in the Permian Basin." *Environmental Science & Technology Letters* 8 (7): 567–73. 2021. https://doi.org/10.1021/acs.estlett.1c00173.

128 Duren et al. 2019.

129 Sherwin et al. 2023.

130 Kunkel et al. 2023.

131 Johnson et al. 2023.

132 Brown et al. 2023.

133 Veritas: https://www.gti.energy/veritas-a-gti-methane-emissions-measurement-and-verification-initiative/; MiQ: https://miq.org/; OGMP2.0: https://ogmpartnership.com/.

B. Emissions Detection and Quantification Platforms and Sensing Types

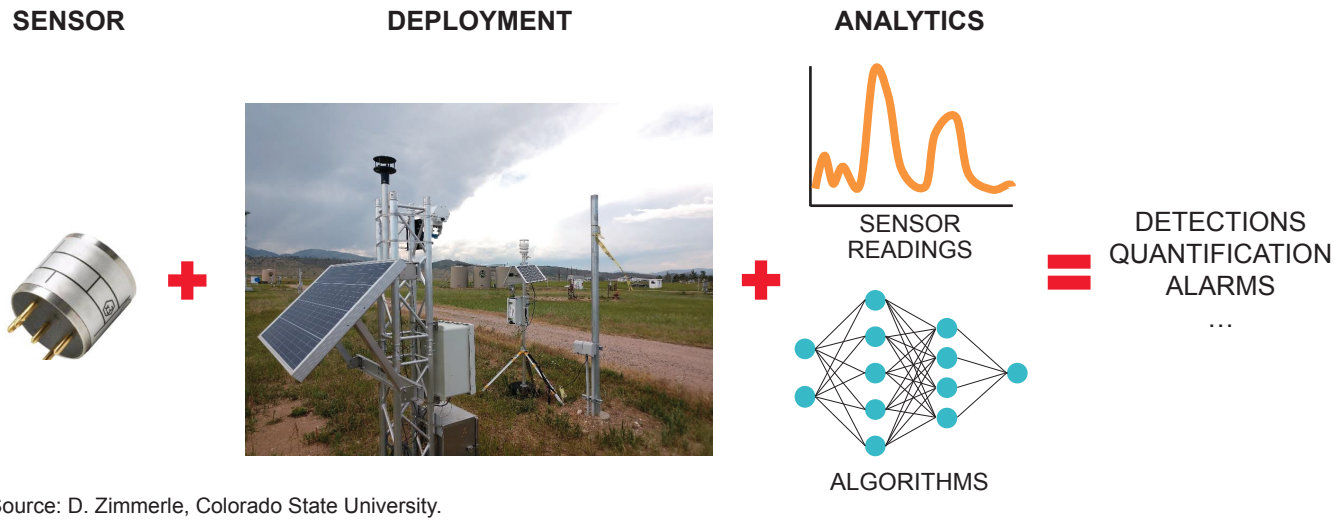
Emissions detection and quantification systems consist of a sensor or sensors, a system that allows for deployment and operation in the field and data analytics to interpret the sensor data. These elements are shown conceptually in Figure 3-4.

All measurement systems use one or more sensors that are responsive to the presence of one or more hydrocarbon species. While some sensors are methane specific, others respond to a wider range of hydrocarbons, and, rarely, selected nonhydrocarbon species. The sensor may detect methane at the sensor location, where the sensor may be fixed, or the sensor may be mobile. Stationary sensors may have limited mobility, such as gimbal-mounted sensors that shift between fields of view (for imaging sensors) or retroreflectors (for path-based laser sensors). Mobile deployment methods include handheld, vehicle, robotic, drone, aerial, high-altitude, and satellite sensors. The sensor may also detect the amount of methane integrated along a path, such as when a laser system is used to sense methane crossing a site boundary or underneath an aircraft. Imaging cameras may create a two-dimensional image of methane concentrations in their field of view.

Additionally, many measurement systems include environmental sensors for wind speed, wind direction, solar radiation, temperature, and/or humidity. These may be deployed directly with the methane sensor as in the case of the fixed-point sensing system, shown in Figure 3-4, or may be deployed separately. Since many methods rely on wind transport of emissions from source to the sensor or the part of the atmosphere that is sampled, systems that do not deploy their own meteorological sensors must acquire that data from another source, such as nearby public sensors (e.g., at airports) or computed weather products (e.g., the High-Resolution Rapid Refresh product from NOAA).

Most sensing systems are coupled with analytics that aim to create actionable information, such as emissions detections, emissions localization, emissions rate quantification, and other outputs. Software analytics may be supplemented by varying degrees of human input and supervision. Outputs may be delivered through dashboards, archived time series of sensor readings, alarms, visual images, and other data products. Often, data will need a layer of human interpretation, such as by an oil and gas operator, to determine what follow-up action is needed.

Most packaged emissions detection and quantification solutions include software algorithms that automate portions, if not the entire, analytic



Source: D. Zimmerle, Colorado State University.

Figure 3-4. *Components of an Emissions Measurement System*

process. Software systems often rely on parameter settings to set the desired behavior of the software. Typically, results are highly dependent on these software settings. Changes in software settings may have an order-of-magnitude impact on what an integrated solution may detect, quantify, or report.

Solution analytics may or may not distinguish between unintended emissions (right column in Figure 3-1) and expected or routine emissions (left column in Figure 3-1). Currently, few commercially available solutions differentiate between routine and unintended emissions. Therefore, operator personnel often need to interpret solution outputs to determine what action, if any, is required to respond to an emissions detection or an abnormally high emissions quantification.

A summary of the general types of emissions detection and quantification systems that have been deployed at oil and natural gas facilities is provided in Table 3-2. A more detailed discussion of units used in measurements and quantification procedures is provided in Appendix D-1 and Appendix D-2 describes the sensing systems in greater detail. Many of these technologies have been developed and deployed within the last 10 years.

C. Evaluating Technology Performance

Methods for evaluating the performance of emissions detection and quantification technologies depend on the purpose of the measurement. For example, if the goal of the measurement is to identify emissions so that they can be mitigated, the most important metrics to evaluate may be detection limits, frequency of measurement, and cost. Quantification of emissions may be less important. In contrast, if the goal of the measurement is to improve the accuracy of annual emissions reporting, emissions quantification accuracy may be the most important metric.

Regardless of the relative importance of different metrics, most evaluations of technologies will require information about detection limits and accuracy in emissions quantification. The most rigorous methods that have been applied for assessing sensor system detection limits and quantification accuracy are single-blind controlled release tests. In single-blind tests, the operators of the measurement technology would not know the magnitude of the controlled release emissions rate and may or may not have known whether and where emissions were occurring. A growing, but still limited, number of controlled release tests for methane detection and quantification technologies are being performed around the world. The Department of Energy funded the creation of a facility at Colorado State University capable of conducting controlled-release testing at a site that simulates the equipment configurations on oil and natural gas production sites. Figure 3-5 shows the Methane Emissions Technology Evaluation Center (METEC, https://energy.colostate.edu/metec/).

As of 2023, METEC has tested approximately 100 emissions detection and quantification technologies. While some data remain confidential, the METEC team has published results for general categories of technologies, such as continuous measurement systems,[134, 135] with the identities of individual technology vendors blinded.

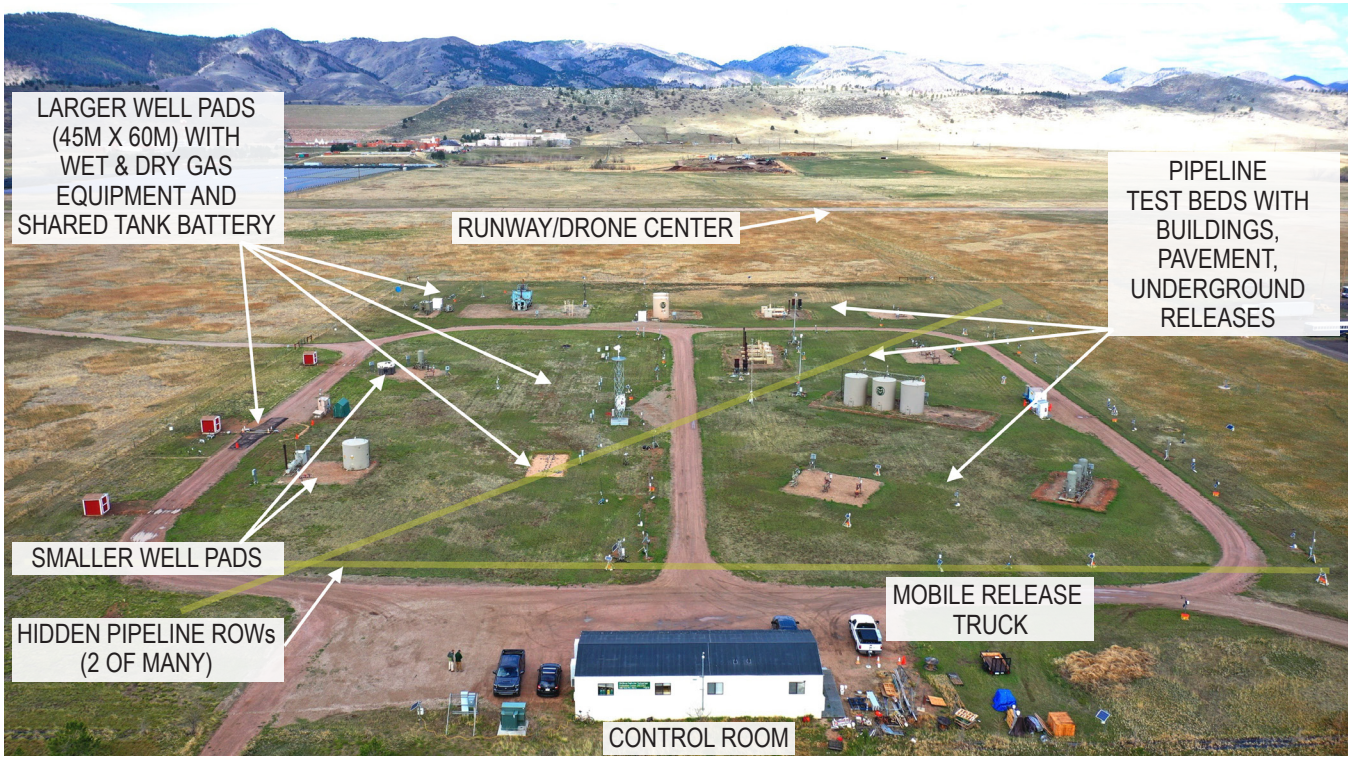
For continuous monitoring systems, limits of emissions detection, probabilities of detection, and uncertainties in emissions quantification were reported for 11 anonymized systems based on single-blind testing at the METEC facility. Methane emissions rates ranging from 0.4 g/hr to 6,400 g/hr were evaluated. The distribution of emissions rates was designed to simulate the distributions of emissions rates observed at oil and natural gas production sites, except for the largest emissions sources. The 11 systems tested included point-source sensors and scanning/imaging systems. Minimum detection limits were generally in the range of a few kg/hr. More than 95% of emissions rates against which the technologies were tested were below the detection limits of typical continuous monitoring systems, indicating that to estimate total site emissions, some additions would need to be made for emissions below detection limits.

134 Bell et al. 2022.

135 Ilonze et al. 2023b.

Measurement Platform	Measurement Type	Primary Segment and Use	Quantification Capabilities
Operator handheld; deployed on-site	Audio, Visual, and Olfactory (AVO) detection	Upstream and downstream, often through public detection of odorants such as mercaptans in downstream natural gas	None
	Optical Gas Imaging (OGI) Camera	All segments	Qualitative
	Quantitative Optical Gas Imaging (qOGI) Camera	All segments, but widest reported uses are in upstream and midstream	Quantification, though with uncertainties that are not well established
	High-flow sampling	Upstream and midstream	Based on instrument sampling rate and observed concentrations; upper bound constrained by sampling rate
	Method 21	Upstream and midstream	Based on correlation equations between sensed concentration of total hydrocarbons and independently measured emissions rates for a limited set of equipment
	Handheld open path laser	Upstream, midstream, and downstream	Semi quantitative (integrated path length concentrations, no emissions rates)
Measurement Platform	**Measurement Type**	**Primary Segment and Use**	**Quantification Capabilities**
Fixed-ground	Fixed-point measurement of concentration	Upstream and midstream	Based on dispersion modeling, statistical pattern matching, or machine learning
	Path-integrated concentration	Upstream and midstream	Based on dispersion modeling; systems that measure paths at multiple heights may obtain whole site emissions rates using mass balance methods
	Remotely operated OGI Camera	Upstream and midstream	Semi quantitative; image processing may allow for quantification
	Micro-Electro-Mechanical Systems (MEMS)	Upstream (emergent)–tank emissions detection	Unknown
Measurement Platform	**Measurement Type**	**Primary Segment and Use**	**Quantification Capabilities**
Mobile-ground	Vehicle mounted instrumentation with tracer release on-site	Upstream and midstream; research activities	Either based on dispersion modeling or on tracer release near source
	Vehicle mounted sensor without tracer (EPA OTM 33A)	Upstream, distribution; research activities	Based on dispersion modeling for sites with well-defined plumes
	Vehicle with Solar Occultation Flux detection	Upstream	Samples entire cross section of plume; emissions determined based on plume modeling
	Dedicated survey vehicles	Distribution and pipeline systems	Based on dispersion models or statistical matching. Dispersion-based quantification is difficult due to complexity of dispersion
Measurement Platform	**Measurement Type**	**Primary Segment and Use**	**Quantification Capabilities**
On-site rotary UAV	On-board sensor; with pilot; mass balance flux curtain	Upstream and midstream	Based on mass balance (a.k.a. 'flux plane') methods
Measurement Platform	**Measurement Type**	**Primary Segment and Use**	**Quantification Capabilities**
Aircraft and fixed-wing drone	On-board instrument measuring along flight path	Upstream, midstream, and downstream	Mass balance spirals or boxes or transects
	Light Detection and Ranging (LiDAR) and hyperspectral imaging	Upstream, midstream, and downstream	Mass balance based on plume mapping
High-altitude stratospheric balloon	Hyperspectral imaging, on-board instrument measuring along flight path	Basin-level coverage for extended periods (weeks)	Mass balance based on plume mapping
Measurement Platform	**Measurement Type**	**Primary Segment and Use**	**Quantification Capabilities**
Satellite	Area mappers	Global coverage of basin-level measurements with high frequency	Current grid resolution is ~50 km^2 with >1,000 kg/hr threshold
	Point measurements	Targeted point sources	Typical reported thresholds of 500 kg/hr-1,000 kg/hr for current instruments with lower thresholds anticipated for instruments scheduled for 2024 and later

Table 3-2. *Emissions Detection and Quantification System Types*



Source: D. Zimmerle, Colorado State University.

Figure 3-5. *Methane Emissions Technology Evaluation Center*

Probability of detection is defined as a function of emissions magnitude,[136] and is determined by analyzing the fraction of controlled release emissions events that were detected (true positives). More broadly, sensing system performance can be characterized by the fraction of all controlled releases that were true positive detections, the fraction of sensor detections that were not controlled releases (false positives), and the fraction of controlled releases that were not detected (false negatives). For continuous monitoring systems evaluated by Bell et al.,[137] the emissions rate at which the probability of detection (true positives) reached 90% ranged from 3 kg/hr to 30 kg/hr, depending on the technology. False positive rates ranged from 0% to 79%.

Quantification uncertainties were high. For controlled release rates of 0.1 kg/hr –1 kg/hr, the mean relative errors of the technologies (95% confidence limits) ranged from −44% to +586% with single estimates between −97% and +2,077%. Upper uncertainty exceeded +900% for four of the eleven technologies. Above 1 kg/hr, mean relative error was −40% to +93%, with two solutions within ±20%, and single-estimate relative errors were from −82% to +448%.

Overall, the METEC evaluation found that current continuous monitoring systems can detect emissions above a few kg/hr, but quantification with better than a factor of two uncertainty remains challenging.

Similar results were obtained for single-blind testing of aircraft-based methane emissions measurement systems.[138, 139, 140] Conrad et al.,[141] evaluated limits of emissions detection, probabilities of detection, and uncertainties in emissions

136 Probability of detection may also be analyzed as a function of wind speed.

137 Bell, C., Ilonze, C., Duggan, A., and Yuan, S. 2023. "Performance of Continuous Emission Monitoring Solutions under a Single-Blind Controlled Testing Protocol." *Environmental Science & Technology* 57, 14, 5794-5805. https://doi.org/10.1021/acs.est.2c09235.

138 Conrad et al. 2023.

139 Bell et al. 2022.

140 Sherwin et al. 2021.

141 Conrad et al. 2023.

quantification for three aircraft-based methane detection and quantification systems. The technologies evaluated were LiDAR and hyperspectral imaging systems. Minimum detection limits and probabilities of detection depend on factors such as wind speed, flight altitude, and sensing system. If a minimum detection limit is defined as an emissions source with a 10% probability of detection, the LiDAR system had an emissions source detection limit of approximately 0.5 kg methane/hr – 2 kg methane/hr at wind speeds ranging from 2 m/s to 8 m/s (lower detection limits at lower wind speeds). The hyperspectral system detection limits ranged from 5 kg/hr–30 kg/hr, respectively. These values are representative and can change with flight altitude, whether the emitted gases have high or low methane concentrations, and other parameters. Probability of detection increased to 90% at source emissions rates of 1.5 kg/hr–7 kg/hr for the LiDAR system and 10 kg/hr–90 kg/hr for the hyperspectral systems, respectively. Again, while representative, these values can change with flight altitude and other parameters. At these detection limits, these technologies will detect mainly large-emissions sources at oil and natural gas facilities. As described in Section I of this chapter, this may represent a large or small fraction of total emissions from a region, depending on the characteristics of the region. Quantification uncertainties had 95% confidence intervals that were generally within a factor of 0.5 to 2 of the controlled release rates.

Overall, some aircraft-based systems can detect emissions rates as low as a few kg/hr with a 90% probability, but detection varies with wind speed and other conditions and detection limits can vary by an order of magnitude, depending on the technology. Emissions rate quantification within a factor of two has been a typical performance.

Only limited controlled release testing for satellite systems has been performed, largely because of the large release rates, hundreds to a thousand or more kg/hr, required for satellite detection. Sherwin et al.,[142] report on the results of controlled releases at an isolated desert location in North America, with no other nearby sources. Emissions rates ranged from 200 kg/hr to 7,200 kg/hr. Data from five different satellite systems were evaluated by five different science teams using a single-blind protocol, with the emissions location, but not the emissions rate, known. The detection and quantification teams correctly identified 71% of all releases. Wide-area satellites detected emissions as low as 1,400 kg/hr. Targeted (point) systems detected the lowest release rates of 200 kg/hr. Quantification was more challenging. While three-quarters (75%) of quantified estimates fell within ± 50% of the metered value, when the five independent teams were provided primary data from the same satellite, the range of estimates provided by the five groups ranged from -80% to +300% of the true controlled release emissions rate.

All these controlled release tests occurred in regions with few, if any, obstructions, or other challenges that might be encountered in midstream and downstream locations. At one of the few controlled release tests at a midstream facility, Liu et al.,[143] report on the performance of detection and quantification systems at a compressor station. Measurement platforms included aircraft, drones, trucks, vans, and ground-based stations, as well as handheld systems. The tests consisted of a total of 17 blind, two-hour releases, with emissions rates ranging from 0.01 kg/hr to 50 kg/hr from single or multiple simultaneous exhaust points. Most systems were able to quantify the emissions rates releases within a factor of two to three, on average, although individual errors could approach an order of magnitude for some technologies. On-source measurements by handheld OGI cameras tended to underestimate emissions while site-level systems tended to overestimate the emissions rates. Multiple simultaneous releases degraded performance. A tracer-based system exhibited the strongest overall performance because using a tracer to characterize atmospheric dispersion minimizes errors that can dominate in other systems.

142 Sherwin et al. 2023.

143 Liu, Y., Paris, J., Broquet, G., Bescós Roy, V., Meixus Fernandez, T., Andersen, R., Russu Berlanga, A., et al. 2024. "Assessment of Current Methane Emissions Quantification Techniques for Natural Gas Midstream Applications." *Atmospheric Measurement Techniques* 17, 1633-1649. https://amt.copernicus.org/articles/17/1633/2024/amt-17-1633-2024-discussion.html.

Additional work indicates that performance in field conditions is worse than in controlled release conditions. A recent side-by-side comparison of two aerial methods at midstream facilities[144] indicated disagreements of 100% at individual facilities and an aggregate disagreement of ≈50% (a factor of two) across 14 facilities.

Overall, at multiple scales, from on-source measurements to satellites, many individual measurement systems are effective at detecting emissions, some at very low limits of detection. All systems, except on-source direct measurements, however, struggle to reliably quantify emissions within a factor of two. This can be attributed to the sources of uncertainties in quantitative emissions measurements. For emissions quantification that is not a direct measurement of an emissions rate, at the source, quantitative emissions estimates have two primary sources of uncertainty: the atmospheric measurement and the methods used to convert the atmospheric concentration into an emissions rate.

In many cases, the measurement of the atmospheric concentration of methane can be accurate and precise. For example, Torres et al.,[145] report on the ability of field deployed continuous methane sensing systems to accurately predict concentrations of methane, using certified gas and other tests. The best-performing field deployable sensing systems were able to achieve agreement with 5%-10% of the concentrations of methane in certified gases used in the field challenges.

The major factor in determining the uncertainty in emissions rates for indirect emissions quantification systems is the process of converting an atmospheric concentration into an emissions rate. Most indirect emissions quantification systems rely on the use of atmospheric dispersion or transport models to estimate emissions rates.[146] For example, fixed-point continuous monitoring systems convert point measurements of methane into an estimated emissions rate by performing atmospheric dispersion modeling. The emissions rate is estimated by specifying the location of the source and determining the emissions rate required to lead to the observed concentration. The accuracy of the estimate depends on multiple factors. One factor is the accuracy of the assumed source location. If a source is farther from, or closer to, the sensor than assumed or if the source is incorrectly identified, the estimate will be inaccurate. Source attribution can be inaccurate due to uncertainties and variability in the direction of the winds that transport methane from the source to the sensor. Another factor is the accuracy of the model of atmospheric dispersion. The accuracy in the dispersion model depends on multiple assumptions within the models as well as responses of plumes to obstructions, accurate wind speed, and other atmospheric data.

Emissions quantification methods that minimize the uncertainties associated with characterizing atmospheric transport from emissions source to point of detection generally have lower uncertainties than methods that do not minimize these uncertainties. For example, tracer and dual tracer techniques estimate emissions rates by making measurements at a distance 100 m–1,000+ m downwind of a site. Atmospheric transport from the source to the measurement location is characterized using on-site release of one or multiple tracers. The tracers are selected to be compounds that are not released by other sources in the region and that can be detected with high accuracy at low concentrations (e.g., sulfur hexafluoride, acetylene, nitrous oxide). The tracers are released at a position near sources at a known rate, and are detected at the measurement location, along with methane. The methane emissions rate is calculated by multiplying the known tracer release rate by the ratio of the observed

144 Brown et al. 2023.

145 Torres, V., Sullivan, D., He'Bert, E., Spinhirne, J., Modi, M., Allen, D.T. 2022. "Field Inter-Comparison of Low-Cost Sensors for Monitoring Methane Emissions from Oil and Gas Production Operations." *Atmospheric Measurement Techniques*. Preprint. https://doi.org/10.5194/amt-2022-2. PREPRINT NOT ACCEPTED.

146 Dispersion assumptions may be (a) used directly, by physically modeling the transport of emissions downwind from source(s) at the facility to the sensors reading downwind concentrations, or (b) used indirectly, by developing libraries prior quantifications that are later matched to current observations using statistical or machine-learning methods. The latter methods assume dispersion in current conditions is similar to that in previously observed conditions.

concentration of methane to the concentration of tracer. No plume modeling is required, however arranging for coordinated tracer releases adds significantly to measurement expenses and logistical difficulties. The uncertainty of this method will vary, depending on how close the tracer release is to the methane emissions source.[147] Generally, one (tracer method) or two tracers (dual tracer) will be deployed. In the case of midstream facilities,[148] the tracer release system had substantially lower errors than all other indirect emissions quantifications (for example, compare Roscioli et al.,[149] to Edie et al.).[150]

In summary, there are opportunities to reduce the uncertainty associated with atmospheric measurements but improved approaches for converting atmospheric measurements of methane emissions into emissions rate measurements will need to be validated based on testing done using emissions with known release rates and other characteristics.

D. Characterizing and Reducing Uncertainties in Emissions Quantification

The types of uncertainties associated with emissions quantification depend on whether the emissions rate is measured directly at the source or indirectly by making an atmospheric measurement at a location remote from the source. For both direct and indirect measurements, there are uncertainties in the measurements made by the device. For indirect measurements, there are also uncertainties associated with converting an atmospheric measurement, made remote from the source, into an estimate of an emissions rate.

Uncertainties in emissions rate measurements made at the source (direct measurements) and atmospheric concentration measurements (used in indirect measurements) are generally characterized using laboratory and field calibrations and uncertainties can be reduced by improving sensor system performance. As described in Section III.C, these uncertainties are among the smallest contributors to overall uncertainty in emissions quantification.

Indirect measurements convert atmospheric concentrations into estimated emissions rates using dispersion models and other atmospheric modeling tools. For example, aircraft- and satellite-borne sensors survey large areas for methane emissions with high efficiency. Presently deployed aircraft and satellites provide methane measurements of methane emissions at global, national, regional, and facility scales and a new generation of instruments promises to provide measurements with improved spatial resolution and sensitivity. These aircraft and satellite measurements have proven useful not only in hydrocarbon production basins, but along pipeline routes, in the vicinity of gas processing plants, and in urban areas where natural gas is distributed and utilized by customers. All these aircraft and satellite measurements are challenged by lack of knowledge of the time-variation of wind fields over the spatial scales of interest. Even the accuracy of emissions rates from local, fixed-ground sensors relies on accurate characterization of emissions plumes, which are highly dependent on detailed three-dimensional wind speeds and directions. Uncertainties in current atmospheric modeling leads to the bulk of the emissions quantification uncertainties reported in Section III.C. The uncertainties can be reduced through more accurate characterization of atmospheric dispersion and transport.

Both direct and indirect measurements are frequently conducted for relatively short periods of time and may be applied to only a subset of an organization's facilities. If these measurements are to be used in creating measurement-informed annual emissions inventories, the measurements must be extrapolated to longer times and additional facilities. This extrapolation also introduces uncertainty.[151, 152] Uncertainties in extrapolating short-duration measurements to annual emissions estimates are reduced through character-

147 Allen et al. 2013.

148 Liu et al., 2023.

149 Roscioli et al. 2015.

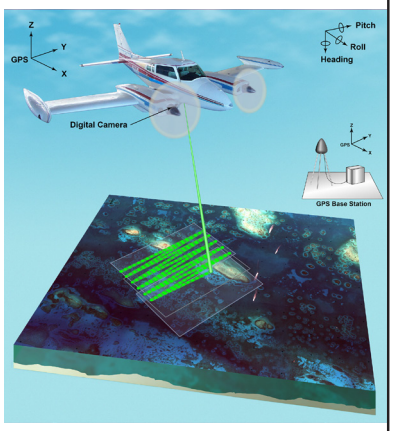
150 Edie et al. 2019.

151 Schissel, Colette, and David T. Allen. 2022. "Impact of the High-Emission Event Duration and Sampling Frequency on the Uncertainty in Emission Estimates." *Environmental Science & Technology Letters* 9 (12): 1063–67. https://doi.org/10.1021/acs.estlett.2c00731.

152 Schissel et al. 2023.

MEASUREMENT UNCERTAINTY

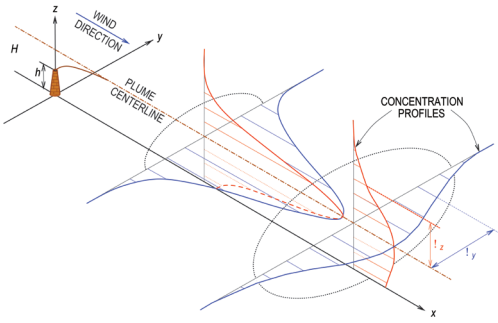
Uncertainty associated with primary measurement technique



Source: U.S. Geological Survey, 2014.

EMISSIONS RATE UNCERTAINTY

Uncertainty associated with converting primary measurement with an emissions rate estimate



Source: Stockie, J., 2019.

EXTRAPOLATION UNCERTAINTY

Uncertainty associated with both
1) extrapolating short-duration measurements to a longer timescale
and
2) extrapolating measurements from a sample population to an entire region

Source: Google Earth, 2023.

Figure 3-6. *Emissions Measurement Practice Uncertainties*

izing the frequency and duration of intermittent emissions events.

These three sources of uncertainty in emissions quantification: measurement uncertainty, emissions rate uncertainty, and extrapolation uncertainty are summarized in Figure 3-6.

E. Findings and Recommendations

FINDING 4: **While technologies for emissions detection and quantification have progressed rapidly and a portfolio of measurement methods can reliably detect emissions over a wide range of emissions rates, uncertainties can still be large for emissions quantifications. Major contributors to the emissions quantification uncertainties are the methods used to convert an atmospheric measurement remote from a source into an estimate of an emissions rate.**

RECOMMENDATION 1: ***The NPC recommends that the Department of Energy and other governmental organizations continue supporting the development and use of emissions detection and quantification technologies with the goal of developing technologies that are accurate, cost-effective, produce actionable information, and that can be deployed in a variety of environments (onshore, offshore, upstream, midstream) in various climates and topographies.***

Specifically, the NPC recommends that:

- **DOE should identify technology gaps common to multiple emissions detection and quantification systems:** Gaps will change over time, requiring ongoing engagement of DOE technology offices with developers and users. Current technology gaps include algorithms, improved/cost-reduced sensors, and adaptable deployment methods. The DOE ARPA-E MONITOR and follow-on SCALE-UP programs, as well as the 2022 iM4 programs provide models of effective funding. Future efforts will be needed to close multisolution, multidomain technology gaps.
- **DOE should identify and fund efforts to close gaps that impede widespread adoption of next-generation solutions:** While critical gaps will change, current focus could include improved models for integrating solutions outputs with operational data systems, improved monitoring system design methods, technologies

for interpreting measurement solution outputs, and tools to integrate measurement solution outputs into regulatory and voluntary reporting programs. DOE's 2022 "IM4" FOA (AOI 4) provides a first example of targeted funding to address the integration of multiple solution outputs. DOE should consider similar, targeted programs focused on integration challenges for individual operators, and/or for basin-scale operator groups, or supply chain emissions assessments.

- DOE should coordinate the identification of common technology gaps with other federal agencies, operators, and solution developers: While DOE is accelerating rapid development of solutions, other federal agencies are grappling with immediate regulatory or programmatic requirements. Subtle changes within these programs could accelerate or chill adoption of next-generation solutions. Robust interagency coordination should focus on incorporating the development trajectory of solutions into federal domestic and international policy initiatives.

FINDING 5: Controlled release testing has provided information, such as detection limits and uncertainties in quantified emissions, that can be used to evaluate measurement technologies. Large numbers of technologies have been tested, but some types of testing have been conducted on an ad hoc basis instead of being conducted using reproducible methodologies at dedicated facilities. The most widely used dedicated facility has been the Methane Emissions Technology Evaluation Center, which was established with funding from the DOE to provide controlled testing capabilities relevant for sources with emissions rates <10 kg/hr at production sites.

RECOMMENDATION 2: *The NPC recommends that DOE sponsor geographically diverse technology evaluation centers addressing sampling environments and emissions types representative of multiple segments of the supply chain. These centers would perform evaluations that would quantify the probability of detection, time to detection, and accuracy (uncertainty and bias) of emissions quantification.*

Specifically, the NPC recommends that:

- **Technology evaluation centers should be established in regions with diverse meteorological and atmospheric conditions:** The performance of sensing elements utilized in methane emissions detection and quantification technologies can change dramatically with weather conditions, including available solar radiation (e.g., for cameras), atmospheric stability, humidity/standing water (cameras, point sensors), wind (most solutions), and temperature (most solutions).
- **Technology evaluation centers should simulate conditions at a variety of facility types:** Data from field studies indicate that production facility emissions differ depending on whether dry gas, wet gas, or oil/associated gas is being produced. Data also indicate that technology performance may differ significantly between supply chain segments, due to the differences in structure size, combustion and vented emissions sources, layout of the facilities, age of the facility, and other factors. Finally, even for the same facility types, the location of the facilities may lead to different emissions characteristics and technology performance. For example, northern facilities may have more enclosed equipment, or state regulations may impact allowable equipment, tank controls, or the flaring of associated gas.
- **Technology evaluation centers should be in representative field settings:** Performance of emissions detection and quantification data analytics are sensitive to surrounding emissions sources, such as nearby field facilities, pipelines, emissions from other sectors, and local topography. Test facilities should include or simulate this type of complexity, increasing the ability of controlled testing to simulate field environments.

Collectively the NPC recommends funding at least five regional technology evaluation centers, modeled on the successful METEC at Colorado State University. Based on the experience of the METEC facility, annual operating budgets should be one-half to one million dollars per year per center, with additional construction budgets of three to six million dollars depending upon complexity and location of the center. These centers should be in diverse regions and should create testing capabilities representative of facilities throughout natural gas supply chains. In addition to creating new centers, centers could also be established at existing training facilities, where these exist (e.g., distribution operators or operator associations have existing training centers).

RECOMMENDATION 3: *The NPC recommends that the DOE, other governmental organizations, academia, technology developers, and industry should advance the methods for methane emissions uncertainty calculation by developing and disseminating algorithms and computer tools.*

The NPC specifically recommends:

- **Uncertainties in concentration measurements should be assessed using standard protocols developed at regional technology evaluation centers:** Uncertainties in atmospheric concentration measurements can be characterized using field protocols, which could be developed and deployed at technology evaluation centers. Protocols may vary depending on the nature of the sensing system and regional meteorological conditions.
- **Uncertainties in quantifying emissions rates should be assessed using standard protocols developed at regional technology evaluation centers:** Atmospheric concentrations are converted to estimated emissions rates using dispersion models and other atmospheric modeling tools. These uncertainties can be quantitatively assessed using controlled releases at regional technology evaluation centers and controlled releases at operating facilities.
- **Protocols for estimating uncertainties in extrapolating short-duration measurements of emissions rates to annual emissions estimates should be developed:** Most emissions rate estimates are based on short-duration measurements at a limited number of facilities. To develop comprehensive annual emissions inventories, short-duration measurements made at a subset of facilities for limited time must be extrapolated to all sites and all times. The uncertainties in extrapolation to facilities where measurements are not available are reduced by sampling more facilities or by careful selection of the sampled population. Uncertainties in extrapolating short-duration measurements to annual emissions estimates are reduced through characterizing the frequency and duration of emissions events. Frequently updated data on regional populations of facilities, equipment, and operations will make extrapolations more accurate. Protocols for these extrapolations should be a work product of regional centers.

RECOMMENDATION 4: *The NPC recommends that the DOE and other governmental organizations support the development of dense networks of meteorological measurement stations in regions likely to be targets for localized and wide-area (local ground through satellites) detection and measurement of methane emissions. Spatially dense, vertically and horizontally resolved, and high temporal frequency measurement of wind velocity (i.e., speed and direction) is a priority.*

Specifically, the NPC recommends that:

- Meteorological data collection and regional wind field modeling should be performed in major production basins. The data collection and analysis could be integrated with the activities of regional technology evaluation centers.

RECOMMENDATION 5: *The NPC recommends the DOE, EPA, and other government agencies sponsor a multistakeholder group to meet*

annually and provide a report with an updated list of emissions detection and quantification technologies for use in the natural gas supply chain. The report would be provided to the DOE, EPA, operators, other state and federal government officials, universities, community groups, NGOs, and other identified stakeholders.

- **Group Members**: The multistakeholder group participants would include DOE, EPA, state environmental agency representatives, natural gas operators, universities, community groups, NGOs, and other stakeholders as determined by the Report Development Leadership.
- **Report Development Leadership Options**: The National Academy of Sciences, Engineering and Medicine (NASEM) has a history of convening stakeholders and developing similar reports. Other options would be to determine whether Resources for the Future, the INGAA Foundation, ONE Future, or other natural-gas-sector trade groups would agree to take the lead in convening a group to develop, finalize, and distribute the report annually. The NASEM, or another agreed upon group, would need to establish a public process for the report development and solicitation of members, scheduling and convening meetings, developing a draft report, determining the report validation process, and finalizing and distributing the report.
- **Report Content**: The report will include, but not be limited to, a list of emissions detection and quantification technologies, their commercial readiness level, a technology gap analysis, and performance metrics of each technology. The performance metrics would include minimum detection limits, probability of detection, time to detection, time to operator notification, methods of operator notification, uncertainties in emissions quantification, physical limitations of particular technology, applications, and estimated cost. The report should also include recommended performance standards for emissions detection and quantification technologies.

IV. MULTISCALE EMISSIONS DETECTION AND QUANTIFICATION SYSTEMS

Emissions sources can have large and small emissions rates, can be routine or unintended, and can be both continuous or intermittent (Figure 3-1); the distribution of these emissions types can vary by supply chain segment, facility type, and location. The complexity, magnitude, spatial variability, and temporal variability of emissions means that no single measurement method is universally applicable. There have been a variety of efforts to develop systems for assisting operators in selecting appropriate technologies (e.g., https://www.ipieca.org/resources/methane-detection-quantification-technologies-upstream). A wide range of measurement methods, with very different capabilities, is required to accurately characterize methane emissions.

In many applications, it is necessary to scale emissions from a set of disjointed observations to an estimate of emissions over a long period of time—annual reporting is common—for a large grouping of facilities, such as one operator's assets, a basin, or supply chain. Temporal and spatial variability complicates this scaling. Integrating multiscale estimation approaches, involving multiple types of measurement technologies, will likely improve scaling.

Figure 3-7 illustrates the challenges introduced by the temporal variability in emissions for one site; these complexities repeat across all sites. Emissions at a site will change due to operational changes at the facility, including changes in operational parameters, equipment, maintenance, or throughput. Periodically, high-rate, short-duration, episodic emissions events may occur, due to short-duration upsets or maintenance. Many of these events are tracked by operators. Additionally, qualitative data indicates that emissions may vary seasonally with temperatures, wind conditions, or accessibility of the site.

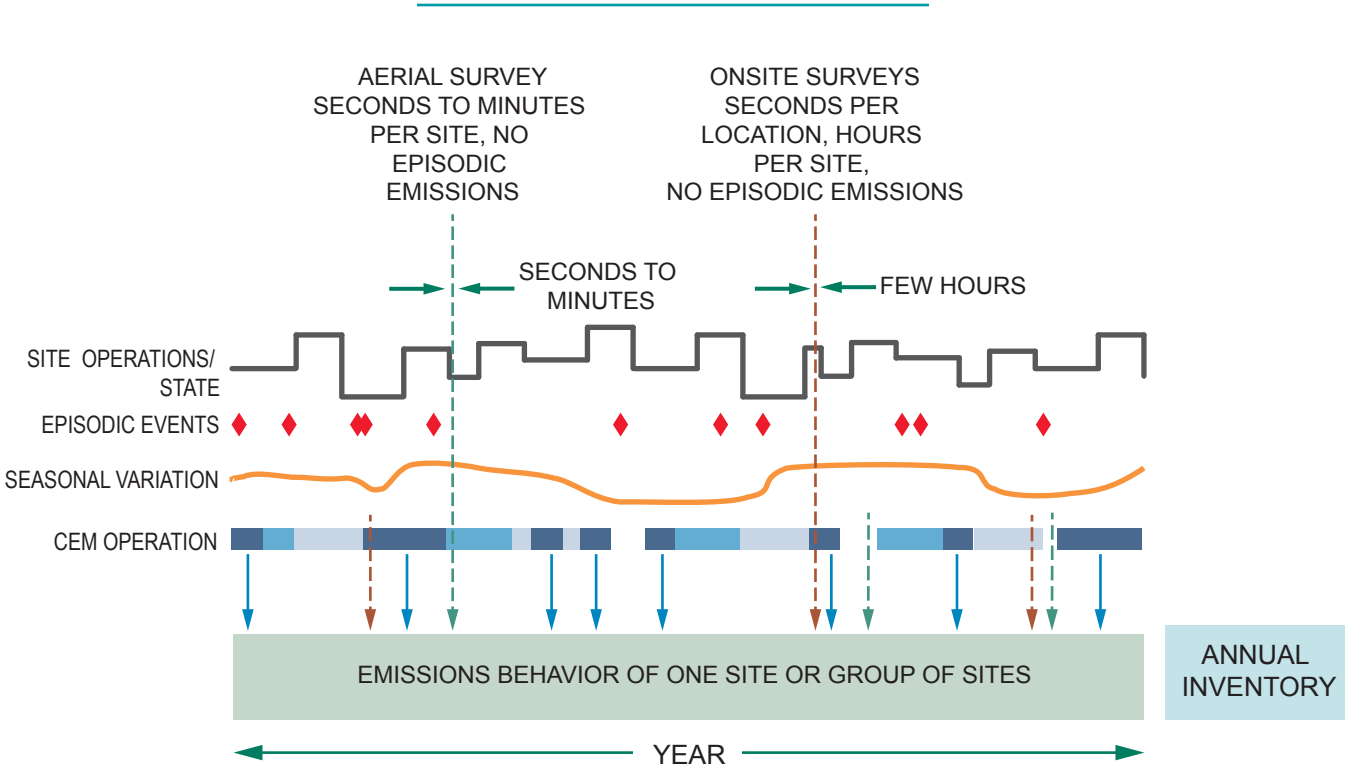
Emissions estimation methods, particularly short-duration measurements, may not completely capture temporal variability. Many methods observe a site over relatively short durations, from a few seconds for a fixed-wing aircraft overflight to a few hours for an on-site

survey, or a few weeks for stratospheric balloon platforms. Additionally, survey methods may observe any one emitter location for only a portion of the full survey time. The quality of outputs from continuously operating on-site monitors (continuous monitoring systems, or CMS) also vary temporally, as methods may need adequate sunlight, sufficient wind, no precipitation, or temperatures within an operating window. Since monitors are deployed at a fixed number of sites and at fixed heights, not all emissions on a site will be always transported by winds to a sensing system location. In Figure 3-7, these CMS temporal characteristics are schematically represented by different patterns for the CMS operation.

Figure 3-7 illustrates both the challenges and promise of multiscale methods. Each estimation method provides insight into site emissions. Coupled with operational data from the facility, these insights provide partial data on emissions over longer durations; methods to integrate these data are an area of active research for both individual sites and sets of sites.

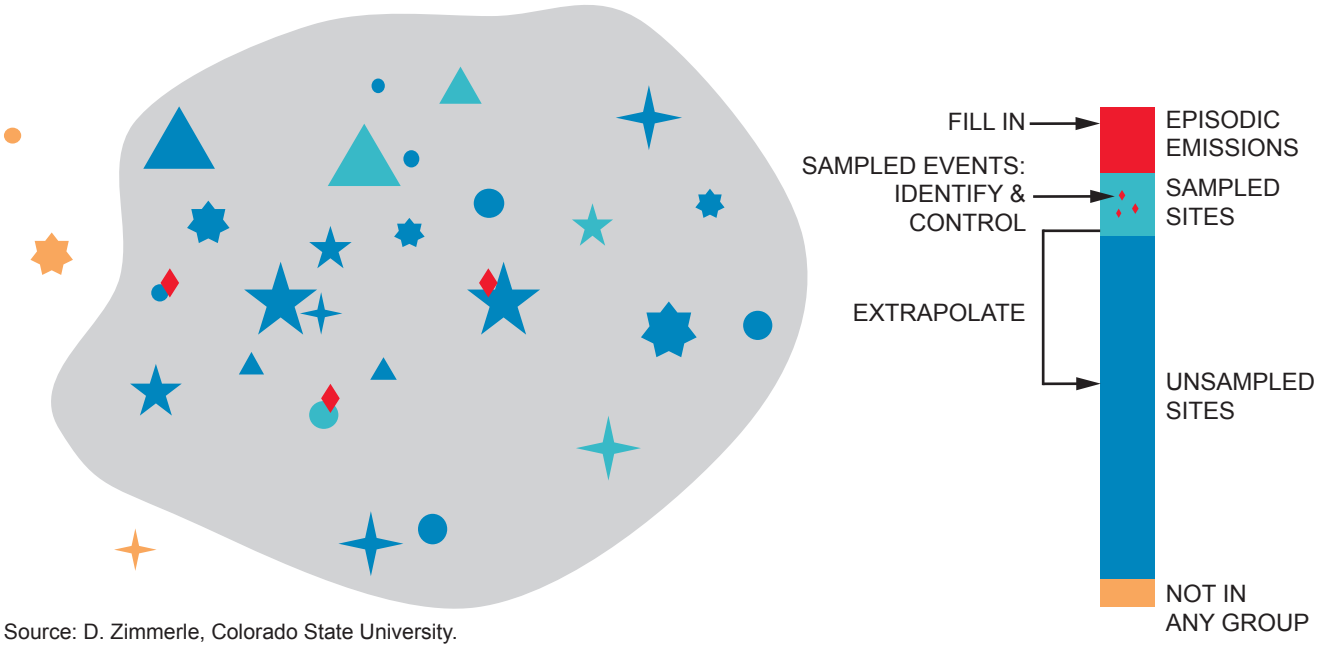
Figure 3-8 schematically illustrates the challenges of scaling emissions spatially from individual observations to an estimate of emissions for a group of sites, such as a basin or an operator's assets. Most sets of sites include a variety of site types. Variation may be due to the size or complexity of a site, when it was constructed, what product the site handles, availability of electricity, or numerous other factors. From the set of sites (gray area), most measurement efforts will sample a subset of the sites (green). The subset may be sites with CMS installed, sites overflown during an aerial or driving inspection, or sites inspected by on-site optical gas imaging. Different methods may be deployed to different sites. Occasionally, measurement technology may encounter an ongoing episodic event, although most such events will likely not be observed.

To scale the observations in Figure 3-8 to the set of facilities, data from sample sites (green) must be extrapolated to unsampled sites (blue). Before extrapolation, sampled data must be controlled for encounters with episodic emissions (red), which are typically difficult to accurately estimate



Source: D. Zimmerle, Colorado State University.

Figure 3-7. *Scaling Challenges Introduced by Temporal Variability in Emissions*



Source: D. Zimmerle, Colorado State University.

Figure 3-8. *Challenges of Scaling Estimations Spatially*

with survey methods or CMS due to the high variability of emissions rate during the event. Direct metering can be used to capture some event types with high accuracy where there is asset operator participation and data capture. Episodic emissions (red) must be added to the total emissions and allocated over an appropriate time scale to be compared with ongoing emissions sampled during the measurement effort. Sampled data must also be controlled for different operational characteristics and operator to operator variation. Finally, to account for emissions at a national or subnational level, scaling efforts must also account for facilities that do not fall within the sets of sites used for estimating emissions. For example, basin-level accounting of production emissions may miss production facilities in smaller historical basins or gathering and processing sites outside the basin boundaries. Similar blind spots exist for analysis by supply chains or similar groupings.

Section III described the performance of individual emissions detection and quantification technologies. Increasingly, however, performance in emissions detection and quantification technologies will be based on the deployment of multiple technologies, in a coordinated manner, at multiple scales; integration of operational data will also be productive. In general, less work has been conducted on how to integrate multiscale information than on developing individual technologies. Recent work evaluating both site-level and basin-level scaling has identified both issues and possible solutions.

For example, a study of production sites by Wang et al.,[153] coupled snapshot measurements with aircraft-based and drone-based sensing with continuous monitoring systems, operator information, and OGI measurements to improve emissions quantification. On-site continuous measurements were used to characterize the frequency and duration of intermittent emissions events; periodic aircraft-based and drone-based measurements were paired with simultaneous measurements from continuous emissions monitors to improve emissions quantification. A similar study of midstream sites by Brown et al.,[154]

153 Wang, J., Daniels, W., Hammerling, D., Harrison, M., Burmaster, K., George, F., and Ravikumar, A. 2022. "Multiscale Methane Measurements at Oil and Natural Gas Facilities Reveal Necessary Frameworks for Improved Emissions Accounting." *Environmental Science & Technology* 56, 20, 14743–14752. https://pubs.acs.org/doi/10.1021/acs.est.2c06211.

154 Brown, J., Harrison, M., Rufael, T., Roman-White, S., Ross, G., George, F., and Zimmerle, D. 2023. "Informing Methane Emissions Inventories Using Facility Aerial Measurements at Midstream Natural Gas Facilities." *Environmental Science & Technology* 57, 39, 14539–14547. https://doi.org/10.1021/acs.est.3c01321.

used similar aerial methods coupled with detailed on-site surveys of emissions. CMS results produced data of low quality for use at these facilities. The study also compared snapshot estimates from the two aerial methods to each other, with two deployment configurations.[155] This process led to several suggested guidelines for multiscale measurements:

1. Snapshot measurements with high accuracy, coupled with information about the operational status of the site at the time of the measurements, are needed to help reconcile measurements with inventory estimates.
2. Measurements to develop distributions of the frequency and duration of intermittent emissions events are key to annualize any snapshot measurement. Because events can last less than 24 hours, high-sampling-rate technologies like continuous monitors will likely be needed to develop timing estimates for emitters that are not captured by operational systems.
3. Detailed record keeping of emissions events, maintenance activities, and upset conditions help reconcile measurements with emissions inventories.
4. Independent verification of measurements and quantified emissions provides additional confidence in results. Survey methods often disagree substantially at individual sites, even when measuring contemporaneously. Variability is less in sets of measurements; however, disagreement between methods is still substantial.

A separate study by Zimmerle et al.,[156] assessed the issues scaling from third-party, site-level, observations to basin-scale estimates, as illustrated in Figure 3-8. The study identified three significant uncertainties that are currently unaddressed in current scaling methods based on third-party observations not coordinated with operators:

1. Substantial improvements in geolocation data for facilities will be needed to identify issues with detection and quantification by anonymous sampling methods.
2. Current methods do not adequately control for episodic events encountered by anonymous sampling. These events are both poorly estimated and may account for 10%-50+% of all emissions sampled on production sites.
3. Performance of methods sampling dilute or dispersed sources[157] is highly variable, producing substantial misestimates of major sources such as compressor driver exhaust and combustion sources.

These recent studies identified that the science needed to overlay operational data with mutiscale emissions measurements of multiple types is diverse, underexplored, and significant. Separate research and development on scaling methods is needed to make emissions detection and quantification technologies successful. This effort will require advances in sampling strategies, simulation, data handling, quality control, and statistical methods.

FINDING 6: **Technologies will increasingly be operated in tiered, multiscale (e.g., source-level, site-level, basin-level) deployments that must be coordinated with operator data systems.**

FINDING 7: **The science and methods of integrating tiered, multiscale deployments, and operational data constitutes a separate and necessary branch of research and development to provide high-accuracy emissions estimates.**

RECOMMENDATION 6: ***The NPC recommends that DOE improve the efficiency and transparency of multiscale methane monitoring of the energy sector by continuing to sponsor public-private partnerships and making measurements across multiple scales.***

155 Brown et al. 2023.

156 Zimmerle et al. 2023.

157 Examples: Dilute: combustion exhaust; Dispersed: underground, aggregated small sources, heavy vegetation.

V. RESPONDING TO EMISSIONS INFORMATION

Effectively responding to emissions detection and quantification information depends on a variety of factors, including the accuracy of the reported emissions rate, the ability to correctly attribute the emissions to specific sources of emissions, and the promptness of sharing alerts from detection events. Section III discusses the criteria for the evaluation of sensor capabilities for various platforms. Effective programs and guidelines for testing and reporting sensor capabilities will enable operators to choose technologies that are appropriate for the type of site and purpose of sensor deployment, including considerations such as onshore or offshore locations, power availability, site complexity, emissions inventory reporting versus mitigation, and other factors.

A. Operator Response to Detections

The success of emissions detection follow-up efforts by operators can vary based on the type of technology used for monitoring, the accuracy of the reported emissions event, the uncertainty associated with the emissions rate, the precision of the reported emissions location, and the time between the emissions event detection and reporting. For operators, accurate information on the location of the emissions is essential in successful response to reported emissions events, especially when data are reported from multiple sources, including third-party monitoring programs such as the United Nations Environmental Programme's International Methane Observatory's Methane Alert and Response System (https://www.unep.org/explore-topics/energy/what-we-do/methane/imeo-action/methane-alert-and-response-system-mars), New Mexico Environmental Department's aerial and satellite monitoring initiative (https://www.env.nm.gov/wp-content/uploads/2023/10/2023-10-03-COMMS-Environment-Department-bolsters-efforts-to-crack-down-on-oil-and-natural-gas-violations-Final.pdf), and the Environmental Defense Fund's methane monitoring program (https://www.edf.org/media/methanesat-adds-jet-aircraft-methane-measurement-arsenal). Effective identification and communication of the location of emissions requires access to publicly available geolocation data for oil and natural gas operations (e.g., wells) and granularity of site or components at the site are needed. This is especially important for detections reported from sensors with low spatial granularity (e.g., TROPOMI) (https://www.tropomi.eu/data-products/methane).

Minimizing the time between the detection of a methane emissions event and reporting the detection to operators is a key component of enabling effective and efficient response to detection events. This is especially important for intermittent sources of emissions. Timely reporting of emissions events to operators allows follow-up while emissions are ongoing or while information on operational conditions at the time of detection is still available. When evaluating methane detection technologies, the processing and communication speed of detection data is an important consideration. Technologies that can rapidly detect, process and relay reliable data enable operators to act swiftly, leading to a more targeted and efficient mitigation effort.

An additional consideration is the type of data included as part of the emissions detection event report. The inclusion of information such as accurate date and time of detection, emissions location and associated uncertainty, emissions quantification and associated uncertainty, and inclusion of auxiliary data such as meteorological data and sensor health will enable operators to better understand and thus respond to an emissions detection event.

Emissions detection and quantification technologies differ in their capabilities for enabling an effective response. Table 3-3 summarizes the deployment and response challenges and advantages of different platforms and technologies in enabling responses, based on operator experiences. Technology types marked as stationary in Table 3-3 would typically be deployed on a single site and would have a site-specific learning period about performance.

Once information is received on emissions detection and quantification, a series of steps, summarized in Figure 3-9, is initiated to respond efficiently and effectively. The precise steps may

Advanced Technology Type	Response and Deployment Advantages	Response and Deployment Challenges	Data Actionability
Satellites (targeting, facility-scale type)	• Scalable • Able to identify large plumes • Regional monitoring • Does not require access to site	• Coarse resolution satellite data need robust detection and QA/QC algorithms to minimize false detections and enable better localization • High detection limit • Smaller fleet size means lower detection frequency • Operational challenges for offshore, near water, snow cover and high wind speeds • Requires high sun angle—mid-day only, issues with high latitudes • Follow up with on-site methods (e.g., OGI) is typically necessary	• Moderately actionable with high quality source attribution data
Aircraft/ high-altitude platforms	• Easy to deploy in United States; challenges deploying internationally • Noninvasive • Lower detection limit than satellites • Fast coverage of large areas, with trade-off between coverage and detection limit • Does not require access to site	• Challenges with snow cover, active precipitation and high wind speeds; daytime only • Snapshot of emissions, typically seconds per site • Follow-up with OGI is necessary for some cases • Depending on technology high frequency may become costly. • Uncertain response to dilute emissions sources (e.g., combustion, engines)	• Most actionable when technology is able to localize to source location on a site • High-quality asset location data required for third-party or anonymous measurements
Drones (flux plane/ mass balance type)	• Faster facility coverage than handheld OGI for large facilities • Does not require manlifts for high sources • Some technologies support subsetting equipment into groups.	• May require site access and safe flight paths within or near site • Relies on consistent winds across site for predictable transport of emissions • Typically requires hours per site; limited number of sites per day	• Somewhat actionable depending on type of emitter and ability to localize to emitter
Drones (OGI camera type)	• Potentially faster facility coverage than handheld OGI • Does not require manlifts for high sources • Good source localization	• Requires site access and safe flight paths within or near site • Poor quantification capability • Typically requires hours per site; limited number of sites per day	• As actionable as OGI surveys
Stationary point sensors detection resolution	• Require little ongoing access to site during normal operation • Operate continuously, with lockouts for low speed or highly variable winds • Typically do not require grid electricity	• Require site access periodically • Challenges with quantification • Challenges with localization • Currently poor performance at complex facilities • Performance/cost trade-offs for number of sensors per site	• Low actionability • Generally fast detection of large emitters with hours-long persistence
Stationary: cameras	• Can localize to equipment or component level • Operate continuously during daylight hours (ambient light versions) or continuously (laser or artificial light versions) • Ability to identify short events not visible to downwind or other survey methods	• Requires site access or access to area around the site • Challenges with quantification • Expensive gimbal required to cover multiple sources • Limited to line of sight; often requires tower for deployment • Some solutions require access to grid electrical powers • May be expensive relative to other sensor types	• Highly actionable • Generally fast detection of large rate emitters, even when short duration
Stationary: Open path lasers, gimballed/ multireflector, and single-path variations	• Can cover multiple sites with one sensor • Ability to actively bracket equipment groups with up- and downwind retroreflectors • Line-integrated emissions detection tolerant of complex wind fields • Requires little site access after installation	• Requires clear area around laser head end and clear lines of sight to retroreflectors; often requires tower • Systems may require grid electricity • Periodic site access for maintenance • Continuously operating units do not sample all locations continuously (e.g., Gimballed units sample on retroreflector for minutes; limited revisit time for each equipment group) • May be expensive relative to other sensor types	• Somewhat actionable–able to isolate to equipment groups
Vehicles	• Can include other complimentary emissions • Effective for urban surveys or smaller footprint sites • Fast screening of multiple sites for large emitters • Lower cost sensor package relative to screening with aircraft; possible to deploy more units • Possible to screen using existing vehicle visits to sites	• Requires site access with driving access on or around the site • Challenges with localization to more precise than equipment group level; generally requires OGI follow-up • Quantification challenges; quantification quality/survey time trade-off	• Somewhat actionable–able to isolate to equipment groups

***Table 3-3.** Deployment and Response Advantages and Challenges for Advanced Sensing Systems*

vary depending on operator response plans, location of the reported emissions, and type of technology that detects the emissions. The steps below represent one example of a procedure to maximize the efficiency of response to alerts of emissions detection and quantification.

1. **Classify the type of alert through desktop analysis:** based on information from the site, information collected previously relating to emissions from that site, and previous experience; identify whether the emissions are intermittent or continuous. Use available operational and other data to understand the source of the reported emissions and the duration of the emissions, if possible.
2. **Inform field operators:** share the details of the emissions reported, including the reporting platform, localization information from the reporting platform, and previous emissions reports from the site with the field operations team. If step #1 resulted in finding the source of emissions, confirm results with field operators. If step #1 did not result in identifying and confirming the source of the emissions, field operators will follow up with information on activities at the site at the time of the emissions detection.
3. **Dispatch personnel for follow-up:** If step #2 did not result in identifying the source of the emissions, then dispatch personnel to the site to follow up with the use of optical gas imaging (OGI) cameras or similar source-level detection technology. Field personnel should expand search to the surrounding area if the emissions source is not found at the indicated location.
4. **Repair or inform:** if the emissions source is found at the site, document the finding and initiate report or work order process if appropriate. If the emissions source is still not found, sweep OGI around the site and notify appropriately if the emissions source is found offsite or on third-party equipment.

The process described in this case study could be supplemented with other approaches, including machine learning. This is an area of active method development.

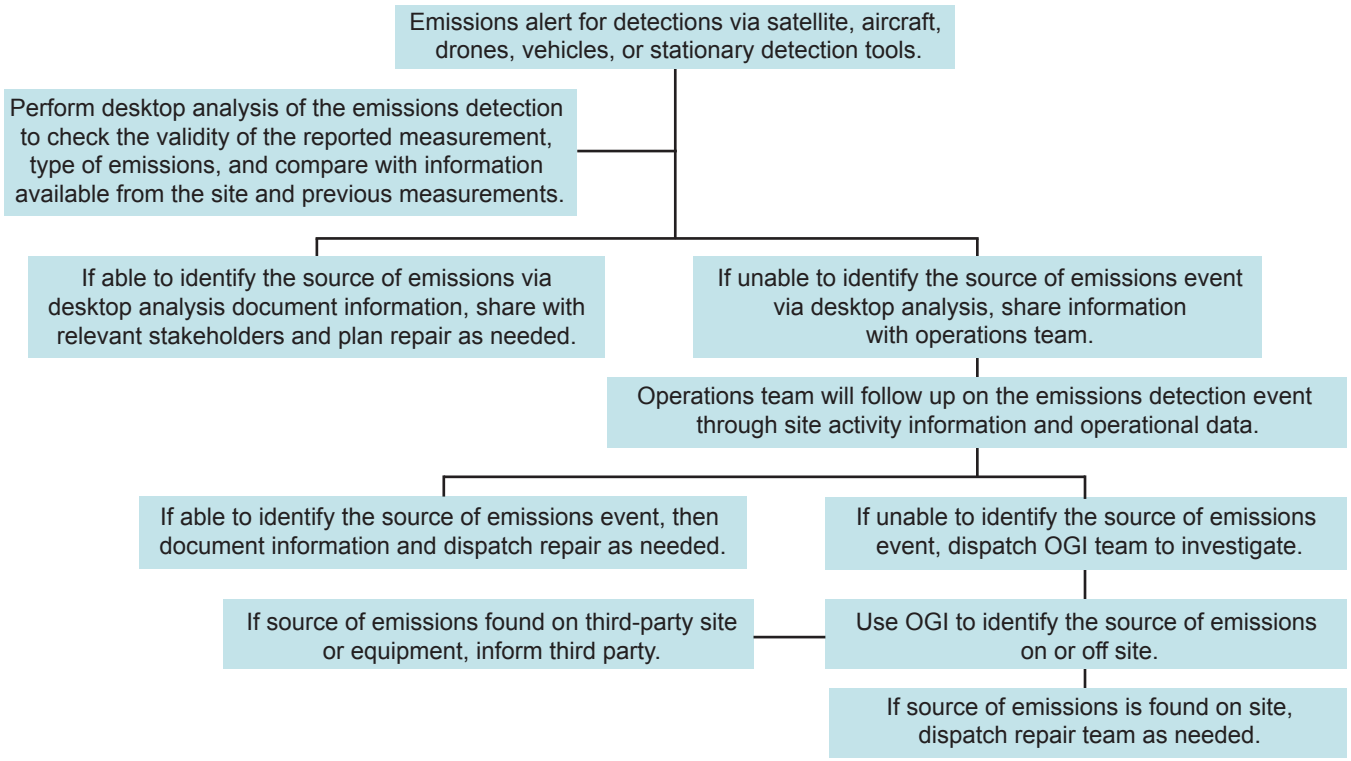


Figure 3-9. *Steps in Responding to Emissions Detection and Quantification*

FINDING 8: The effectiveness of operator response to emissions detection and quantification information is strongly related to the availability of data for accurate attribution of detected emissions. The use of satellite, aerial, and ground-based continuous sensors in combination can create a holistic picture of methane emissions and their sources only if data are available for correct attribution of detected emissions to the sources of emissions.

B. Considerations for Third-Party Surveys

Prior to operator notification (as in Section V.A), special consideration is required for emissions surveys conducted by third parties, i.e., not by or for the operator. Examples of third-party surveys include satellite surveys by environmental NGOs and aerial or driving surveys by NGOs or regulators. In these surveys, the emissions detection and quantification technologies are deployed across a large number of facilities, which may be geographically concentrated (e.g., a basin) or widely distributed (e.g., transmission compressor stations). Typically, third-party survey programs intend results to be public. Results from third-party sampling may be a key component of the 'super-emitter program' in EPA's 2023 methane regulation.

Third-party surveys, by their nature, measure methane concentrations in the atmospheric column and typically identify emissions plumes based on geolocation data. While these surveys are a useful tool in detecting large intermittent plumes and providing timely alerts for mitigation, there are inherent uncertainties in their emissions quantifications and source attribution that arise. These uncertainties, specifically geolocation, wind conditions, and emissions duration, result in inaccuracies that require additional confirmation for accurate emissions quantification and source attribution.

Wide-area survey methods typically identify emissions plumes, which are geospatially located and tagged with the exact time of sampling. To dispatch these detections to operators, the plume must be attached to a facility location, and the facility location must be tagged with the appropriate operator to notify. Unfortunately, public data on oil and natural gas operations beyond well locations is fragmented across multiple databases held at the state and national levels. Frequently, these databases are the result of regulatory reporting that do not include all facilities. Facilities are omitted from reporting due to size, facility type, or similar limitations. As an example, approximately one-third of transmission and storage sites exceed the reporting threshold for the GHGRP.[158] Additionally, many public databases have no coordinates for sites, and/or coordinates are poorly quality controlled. For example, coordinates may indicate the access gate on the nearest public road or identify an office location rather than the site location.[159] Ownership of production sites changes frequently. There is often a substantial lag between reporting and public accessibility, during which time sites may be sold or change status.

Where site coordinates are available, public databases include little information on site size or function. As an example, while the location of wellheads is typically known and readily accessible, gas and liquids processing equipment may be located at well pads up to half a mile or more away from the wellhead. Well pad locations are infrequently included in databases (Colorado's reporting program is an exception). Since many modern production system designs locate wells distant from well pads, the location where most emissions occur—the well pad—is not readily available.

Finally, sites from multiple operators may be adjacent or coincident, or sites may be large enough that an emissions location is tens of meters away from the defined GIS coordinate location for the site. Recent work suggests that boundaries of sites are necessary to properly assign plumes to facilities, and boundaries may be acquired from operator data or from satellite imagery.[160]

FINDING 9: Public data on oil and natural gas operations can be fragmented across different databases and may lack standardization or be challenging to access. A holistic

158 Brandt et al. 2015.

159 Zimmerle et al. 2023.

160 Zimmerle et al. 2023.

understanding of the available databases; the validity of data included, whether the data are current or not; and the possibility of automation of access to such databases are the first steps to developing a user-friendly and publicly accessible database that lends itself to automated queries when needed. A unified, robust database that is easy to navigate, publicly available, and updated from the latest data sources is needed. These types of data are especially important for third-party detections from remote sensing platforms such as satellites and aerial surveys.

RECOMMENDATION 7: *The NPC recommends that DOE fund studies that target the improvement of accuracy, availability, and accessibility of publicly available data that are used for site or facility-scale attribution of detected emissions sources.*

VI. INTEGRATING EMISSIONS DETECTION AND QUANTIFICATION INFORMATION WITH OPERATOR DATA

Parametric or operational data take a variety of forms and includes process information like temperatures, pressures, and flow rates. The data are often recorded in data management systems like SCADA[161] that can be analyzed by operators. The availability of parametric monitoring data is variable for many reasons, including facility vintage and design, availability of data system connectivity, and the choice of monitoring equipment that is prioritized by operational needs rather than emissions management. When available, however, operator parametric data can provide information important for emissions detection, quantification, and duration. For example, a thermocouple on a flare tip may be used to monitor the presence of flame at a flare. A pressure measurement on a process vessel may provide information about whether the vessel is venting and the amount of material in the vessel. Operational data can also include information from inspections or maintenance activities. These data can be useful tools to provide context to, and insights concerning, results of methane emissions detection, quantification, and duration. Incorporating operational or parametric data into the analysis of detected methane emissions allows tracking and possible prediction of emissions from monitored sources. Where uncertainties and challenges with data sets generated as part of advanced detection technology exist, the use of parametric or operational data can provide context and be used to assess emissions detection and provide information on the duration of the emissions event.

Additionally, some emissions sources may be monitored by continuously operating flow meters, providing accurate measurement of emissions and trending data for predictive maintenance. Examples include rod packing vents on reciprocating compressors, shaft seals on centrifugal compressors, or emissions from tank overpressure vents.

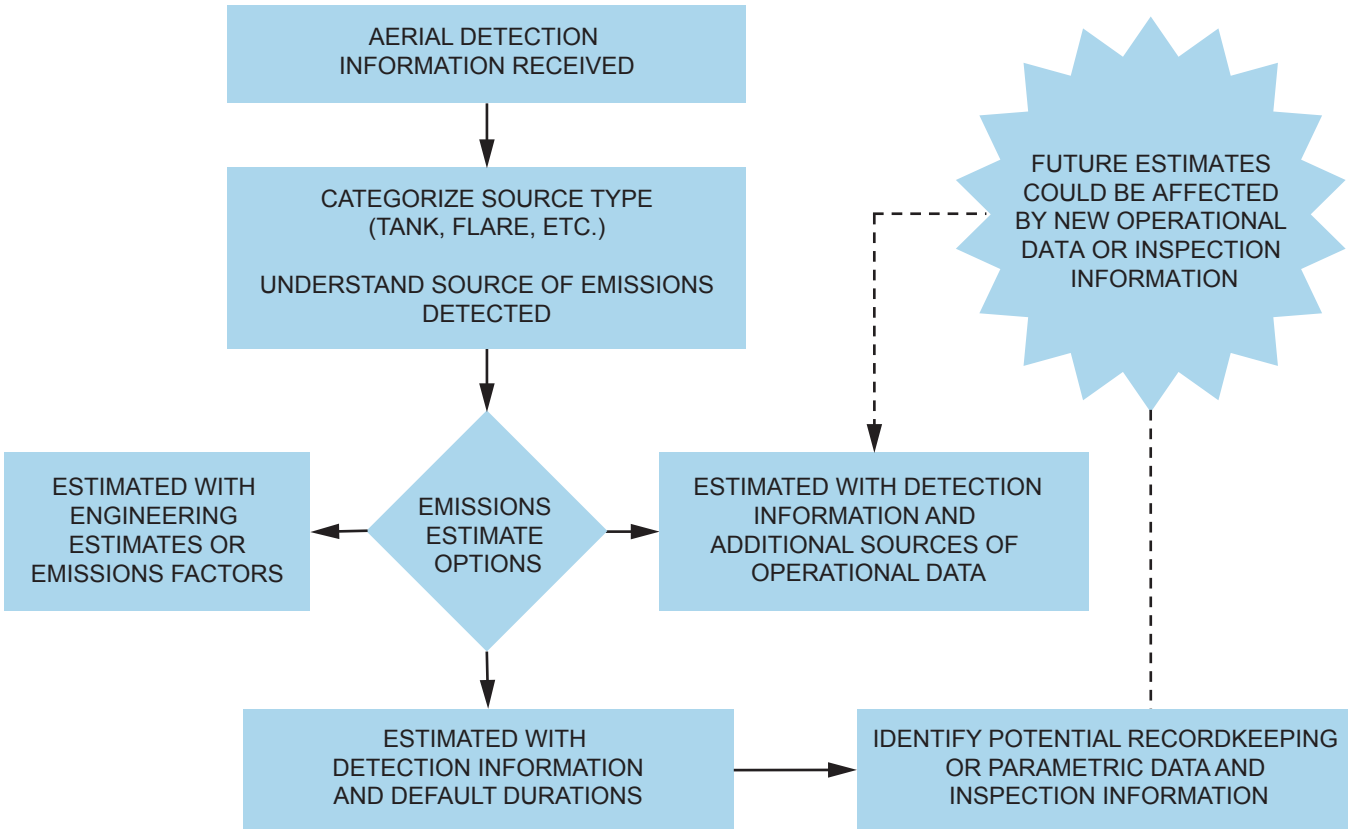
Higgins et al.,[162] provides an example of the use case of parametric or operational data combined with aerial detection. Figure 3-10 shows the steps in the response and summarizes the role of operator data in the response and Table 3-4 provides examples of potential uses of parametric data.

Large-scale incorporation of operator data with emissions detection and quantification data will generate very large data sets that will require rapid analysis in order to be most effective in emissions mitigation. Machine learning and artificial intelligence systems have the potential to contribute to these rapid analyses in multiple ways.

For example, most current analyses of emissions data use measurements from individual sensing systems, occasionally comparing and attempting to synthesize multiple data from multiple technologies, as described in Section IV of this chapter. Machine learning and artificial intelligence systems have the potential to automate this integration.

161 SCADA – Supervisory Control and Data Acquisition: A system that monitors and controls industrial processes and devices. In oil and natural gas operations, SCADA typically gathers, aggregates, and presents data collected from equipment across multiple sites.

162 Higgins, S., Hecobian, A., Baasandorj, M., and Pacsi, A. 2024. "A Practical Framework for Oil and Gas Operators to Estimate Methane Emission Duration Using Operational Data." *SPE Journal* SPE-219445-PA. https://doi.org/10.2118/219445-PA.



Source: Higgins et al., 2024.

Figure 3-10. *Steps in the Response to an Aerial Detection Integrated with the Use of Operator Data*

Most current analyses of emissions data require human intervention when comparing emissions data to operational data. Again, machine learning and artificial intelligence systems have the potential to automate integration of emissions data with process or parametric data to recommend action.

Finally, the integration of process and emissions data, analyzed using machine learning and artificial intelligence methods opens the possibility for developing systems that could predict, and potentially prevent, process conditions that would lead to emissions.

To achieve their potential, machine learning and artificial intelligence tools will need extensive test and learning data sets that combine emissions and operational data. Test and learning data sets could be both synthetic (e.g., digital twins) or could be based on multiscale measurement campaigns. Development of the tools would require teams with expertise in machine learning/artificial intelligence, emissions measurements and oil and natural gas facility operations.

FINDING 10: **Operational and process data can be used to better understand sources of emissions and estimate duration of emissions. Data that are integrated with operations and process parameters offer an advanced and multifaceted approach to emissions management. The use of operational or process data not only allows for real-time monitoring of some types of emissions but also can be used to enhance the data collected from advanced emissions monitoring technologies such as satellite and aerial platforms for better attribution of detected emissions. Additionally, these data (process and operational) can be used to estimate the duration of emissions detected by advanced technologies where other sources of data are not available.**

Emissions Source from Aerial Detection	Underlying Cause of Emissions	Source of Information	Type of Record	Description of Use to Define Event Duration
Tank	Tank Overpressure	Tank Pressure Monitoring	Parametric Data	Changes in tank pressure monitoring data can define the start and end of the venting associated with the detection.
Tank	Open Thief Hatch	Tank Pressure Monitoring	Operator Routine Duties	As part of routine duties, operators may check storage tank thief hatches to ensure they are closed and latched. Records confirming thief hatch is closed and latched could help define the period associated with a detected emission.
Tank	Stuck Dump Valve on Separator	Separator Level Alarm	Parametric Data	A dump valve stuck in the open position on a separator would cause the separator liquid level to drop. A liquid low-level set point may cause the separator to shut-in when it is reached. However, storage tank emissions may occur before the shut-in. Separator alarm logs and levels could help define the timing of the event.
Tank	Liquid Unloading	Operator Records	Liquid Unloading Log	The date and time of the aerial detection can be matched with the period from operator records that an unloading was occurring at the site. This would point to engineering estimates as being more appropriate for emissions estimates than the field detection information.
Flare	Unlit Flare	Thermocouple or Flame Scanners, Flowmeter	Parametric Data	Flow meter readings can indicate the beginning and end of a flaring event. Thermocouples or flame scanners indicate presence or absence of flame on the flare pilot. If the temperature dropped during a flaring event, it would indicate the flame went out and be the beginning of the time for the event.
Flare	Unlit Flare	Operator Records	Operator Routine Duties	Date and time when operator last visited the site and noted the flare was lit provides a data point for when the flare had previously been lit.
Separator	Unlit Heater Pilot Light	Operator Records	Operator Routine Duties	Date and time when operator last visited the site and noted that the separator heater pilot as lit provides a data point for when the separator heater pilot had previously been lit.
Separator	Unlit Heater Pilot Light	LDAR Records	Operator Routine Duties	Date and time when OGI technician last visited the site and did not note separator heater pilot was unlit may provide a data point for when the separator heater pilot had previously been lit.
Separator	Unlit Heater Pilot Light	Thermocouple	Parametric Data	Date and time when production fluids in separator last came up to set point on temperature controller and then failed to come up to set point after dropping below set point on temperature controller can provide a time estimate for when separator heater pilot had previously been lit.

Source: Higgins et al., 2024.

Table 3-4. *Potential Uses of Parametric Data in Emissions Detection and Quantification*

FINDING 11: Operational and process data could be combined with methane monitoring data from advanced technologies for advanced data analytics that may prevent emissions.

FINDING 12: Operational and process data can be an effective tool for methane emissions event monitoring where deployment of advanced technologies is challenging. In cases where the deployment of advanced methane monitoring technologies is constrained due to factors such as power availability, site access, seasonal restrictions, or economics, operational and process data can serve as an effective surrogate for direct monitoring of some methane emissions

sources. Existing operational data can be leveraged for methane emissions event monitoring from some sources or used in combination with data analytics tools, such as machine learning and artificial intelligence, for preventive maintenance.

RECOMMENDATION 8: *The NPC recommends that DOE continue to support technology innovations to reduce cost and improve the effectiveness of next-generation, low-emitting facilities across multiple supply chain sectors that integrate emissions detection and quantification systems with other data collection systems. Innovations include, but are not limited to, development of predictive emissions monitoring systems and machine learning systems for data analysis, targeting metering, and process sensing/monitoring systems.*

VII. BARRIERS TO DEPLOYMENT AND SCALE-UP

Effective deployment of methane emissions detection and quantification requires an interlocking set of technologies, tools, and expertise. For an operator to deploy advanced methods, there must be:

1. Regulatory support for use of advanced methods (Section III) in emissions detection and quantification to satisfy regulatory requirements, and for supporting tiered deployments (Section IV).
2. Advanced methods must be cost-effective for deployment, including all direct and indirect costs.
3. Skilled personnel must be available.
4. Results must be widely known and accepted, which requires uncertainties to be clearly understood.
5. Sites must be physically able to support advanced methods.

This section covers each of these issues.

A. Regulation

Ultimately, superior methane emissions detection and quantification will be deployed only if operators can include results from advanced methods into areas where existing emissions detection and quantification are currently required. A critical subset of those requirements is regulatory reporting. Regulations can encourage or discourage the use of advanced technologies.

Regulatory reporting documents current emissions. Data requirements include emissions inventory updates, sitewide emissions rate estimates, and/or evidence that equipment-level monitoring for specific equipment types (e.g., tank controls) was correctly executed. Increasingly, reporting results are being considered as inputs to assess regulatory fees, such as the methane Waste Emission Charge in the IRA, increasing the stakes for accurate and defensible emissions estimates.

1. Conflicting Regulations in Overlapping Jurisdictions

The U.S. regulatory environment is complex, with overlapping federal, interagency, state, and local requirements. Other requirements may impact trade in natural gas products. Misalignment between regulatory requirements (federal – interagency, state, local) complicates the adoption and scale-up of advanced detection technologies. Regulations at state and national levels may have similar reporting requirements but lack options to use different tools or require different tools. Meeting conflicting requirements between these programs increases effort and costs. In a worst-case scenario, if one jurisdiction allows, and another overlapping jurisdiction does not allow, a technology or measurement program, duplicate programs may be required, increasing costs and erecting barriers to widespread adoption of advanced technology.

Similarly, many operators may need to report to several voluntary reporting programs to meet the requirements of customers or investors. Each of these programs may specify different detection, reconciliation, or certification tools, which may also conflict with regulatory reporting requirements.

Achieving consistency between disparate programs typically requires extensive time but could substantially reduce barriers to widespread adoption of the best-available methods for methane emissions measurement and mitigation. Additionally, building flexibility in emissions detection and quantification requirements into voluntary and regulatory programs would encourage an integrative approach to advanced technologies.

2. Risks Related to Conflicts in Reporting

Differences between reporting programs may result in substantial differences in reported emissions. While EPA reporting often relies on EPA-published emissions factors or calculation methods, other reporting programs may require direct-measurement or enhanced-calculation methods. Operators reporting different emissions data for the same assets to different organizations face challenges when reported results have an impact on financial statements or regulatory certifications. Revised and more flexible reporting standards, such as the inclusion of measurement-informed emissions factors, could minimize this risk and incentivize the use of advanced technology.

3. Potentially Punitive Effects of Regulatory Programs

Current regulatory reporting for greenhouse gases, particularly at the U.S. national level, has been specified in detail within EPA regulations (e.g., 40 CFR Part 98 Subparts W and C). Regulations identify specific locations to screen for emissions and specific methods of calculating, measuring, or estimating emissions. In contrast, advanced emissions detection and quantification technologies typically look at *all* equipment and *all* sources. Therefore, these technologies are likely to find emitters that were not included in the previous, detailed, reporting regulations, and reporting increased or decreased emissions may have impacts on future methane waste fees.

Advanced technologies provide methods to identify and enable the mitigation of a wide range of emissions, independent of the regulatory source classification. However, to incentivize the use of these technologies, regulatory programs should consider how to integrate results from these technologies while retaining regulators' needs to engage in enforcement for repeat emissions violations.

4. Approval Processes for Regulatory Use of Advance Detection and Measurement Technologies

Regulations governing stationary sources do not readily incorporate technology innovations due to their slow review schedules relative to the pace of innovation. (typically every eight years for Clean Air Act (CAA) rules, 42 U.S Code § 7411(b)(1)(B); 42 U.S Code § 7412(d)(6)) Recognizing this mismatch, Congress included mechanisms for alternative compliance, called Alternative Means of Emissions Limitations (AMEL) within the statutes (42 U.S Code § 7411(h)(3), 42 U.S Code § 7412(h)(3)), but utilization of these provisions is onerous for both the EPA and the regulated community. These AMEL provisions allow for an applicant to petition the EPA to allow for the applicant to apply an alternative "system of continuous emissions reduction (including the use of specific technology)" that the applicant demonstrates, to the satisfaction of the Administrator, "will achieve a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such air pollutant achieved under the requirements" of provisions of an applicable standard.

The agency, to process such an application, must bear the administrative burden of a notice and comment rulemaking, and for a rulemaking that is otherwise discretionary. Like other agencies, the EPA is often fully engaged with non-discretionary obligations. Consequently, this process is protracted, expensive, and fraught with uncertainty. For example, despite the rapid development in alternative monitoring technologies that could revolutionize oil and natural gas leak detection programs, only one application has been made to EPA for its use to date. In early 2021, Exxon Mobil Corporation filed an application to use Bridger Photonics' Gas Mapping aircraft-based LiDAR system to satisfy its leak detection and repair obligations through an AMEL for one of its assets. As of the end of 2023, some 30 months later, no action has been taken to accept or deny the application.

A typical example of the prolonged nature of these applications, even when successful, can be found in the case of AMEL applications for Multipoint Ground Flares. Using the same CAA provisions, Dow Chemical Company formally requested AMEL for an alternative flare technology for two of its chemical plants in August 2014. ExxonMobil made a similar application to use the same technology at two of its plants in October 2014. These formal applications followed a long period of discussions with EPA and flare testing on the part of the companies. EPA posted a notice in the federal register soliciting comments and acknowledging the approval requests in February 2014 (80 FR 8023). The AMEL notice of approval was posted in the Federal Register August 31, 2015 (80 FR 52426), simultaneously soliciting comment on another application to use the same technology, and proposing a framework by which future applicants should prepare their equivalency demonstration. At least nine applications were submitted to use this technology in chemical plants. EPA has very recently (April 2023; https://www.federalregister.gov/documents/2023/04/25/2023-07188/new-source-performance-standards-for-the-synthetic-organic-chemical-manufacturing-industry-and) proposed to incorporate this option into its rules for one industry, after nearly 10 years of companies having to individually petition for each instance of use of this technology.

In some cases, states and other governments have developed programs that have approved the use of novel technologies more quickly. Examples include Colorado's Approved Instrument Monitoring Method (AIMM) (Colorado Department of Public Health and Environment n.d.; AIMM for oil & gas | Department of Public Health & Environment (colorado.gov)), or Alberta's Alt-FEMP program (Hiebert, 2018; Alternative Fugitive Emission Management Program (alt-FEMP) Approvals | Alberta Energy Regulator (aer.ca)).

EPA has incorporated processes in some cases where there are high volumes of AMEL applications anticipated, such as adopting, through notice and comment rulemaking, a framework to streamline the testing requirements and elements of the application for Multipoint Ground Flares, and with less specificity, provided high-level guidelines on what would be evaluated specifically for AMEL applications within NSPS OOOOa (§60.5398a).

The EPA could improve the process of incorporating advanced emissions detection technology as part of regulatory requirements for monitoring and mitigation of methane. In its NSPS OOOOb and Emissions Guidelines rulemaking, EPA included a specific option to allow for alternative fugitive emissions standards that could be published as alternative standards, which would be, upon approval, "available for use by any owner or operator in meeting the relevant standards and requirements established for facilities" under the NSPS OOOOb. This would offer a significant improvement over the traditional AMEL process because an approved method would be generally available. This encourages owners and technology providers to collaborate, which may reduce the burden for individual operators and derisk technology trials for providers, however, mechanisms will need to be developed to permit sharing of information. Other technology supportive agencies, such as DOE, could facilitate regional trials that would satisfy the testing requirements.

B. Technology Deployment and Integration Cost

Methane detection and quantification technology development is an evolving landscape. Two broad modes of deployment have been observed. First, technology providers have developed solutions deployed to oil and natural gas operator sites under contracts with the oil and natural gas operators; cost data are not publicly available under these contracts. Second, several oil and natural gas operators have developed their own emissions detection and quantification approaches; cost data for these approaches is also not available.

As of this writing, many active emissions detection and quantification technology providers have been deployed on a trial basis with one or more oil and natural gas operators, while fewer providers have deployed widely. A true, cost-competitive structure has not yet evolved but is likely to evolve over the next three to five years. Given the lack of publicly available data, no specific cost information can be presented. However, multiple

solutions utilize the same deployment strategies, and these strategies drive underlying operational costs by deployment mode. Fundamental cost drivers include cost of required instrumentation, cost to transport the sensor package during a survey, and personnel who need to be deployed during a survey or to guide postprocessing of data. While these costs cannot be discussed with specificity, observations can be made on industry-standard cost drivers for each.

Table 3-5 provides a first-order analysis of costs per site and per year for a variety of solution types. All estimates are generic and consider multiple aspects of deployment, which can be compared between solutions:

1. Cost of the instrumentation package
2. The number of technicians deployed for a survey
3. The time required to sample sites
4. Labor required to supervise the postprocessing of data collected during a survey, or to provide supervision and data monitoring for a Continuous Monitoring Systems

Costs are normalized by estimating the number of sites that can be covered per day and number of operational days per year.

The analysis does not include investment costs. Solution developers must amortize investments in instrumentation, data management, analytics, product packaging, support, and marketing. Given the sophistication of analytics required for many solutions, these costs, even when amortized over many deployments, may exceed the deployment costs identified here.

Table 3-5 does not present trade-offs between cost and performance. The choice of solution must be fit-for-purpose. One solution may provide better diagnostics for a suspected emissions problem at a lower cost than a different solution deployed at the same site. For example, the three aircraft variants in Table 3-5 represent three significantly different detection limits: As the number of sites per day increases, the aircraft flies higher and faster, detection limit increases, and localization precision decreases. While the high-altitude aircraft solution may cost less per survey, the benefits of the survey may be reduced if targeted emitters fall below the solution's detection limits or are too intermittent to be reliably detected.

The cost of an advanced emissions detection and quantification solution often represents a fraction of the total cost required for an oil and natural gas operator to integrate the solution into internal processes. Integration costs include training, skilled personnel, information systems integration, and responding to emissions detections (see Section V). Currently, these areas lack standardization. Training programs have not been developed and/or standardized. For example, while there is regulatory guidance for training OGI operators[163] there is no guidance for the other methods discussed in this report. No standards exist for data interchange to/from solution providers; integration of each solution requires specific process and information systems development, including cybersecurity issues. Integration is also needed with SCADA systems.

Development of consistent technology integration frameworks would ease integration of solutions overall, and lower barriers to the adoption of new solutions, combining solutions into multi-scale systems (Section IV) or substituting similar solutions as the market evolves and becomes more competitive.

FINDING 13: **Lack of consistent standards for data interchange increases the costs of adopting advanced emissions detection and quantification and creates barriers for adopting new solutions, new operating modes, or combining inputs from multiple solutions.**

C. Shortage of Skilled Personnel

Deployment of advanced emissions detection and quantification requires new skillsets for employees. Additional skills will be required at all levels of technical employment, from technicians

163 Footer, Tracey. 2015. "U.S. Technical Support Document: Optical Gas Imaging Protocol, 40 CFR Part 60, Appendix K, Revision 5." Technical Support Document EPA-HQ-OAR-2010-0505-4949. Eastern Research Group. https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-4949.

Technology Type	Sites Per Day	Deployed Personnel (person-days/day)	Post-Processing Estimate (person-days/day)	Total Labor (person-days per site)	Survey Deployment Transport Requirement (category)	Instrument Package Required	Instrument Package Cost (assume 3-year life)	Backend Analysis Complexity	Total Deployment Cost Per Site Per Survey (order of magnitude)	Total Deployment Cost Per Site Per Year (order of magnitude, 4 surveys per year)
Survey Methods										
OGI survey	2	2	1	1.500	vehicle	OGI camera	moderate	low	1000s of $	10k's of $
Satellites (targeting, facility scale type	100	0	0.5			satellite instrument	extremely high	high	10s of $	100s of $
Aircraft (low altitude)	100	2	1	0.030	small aircraft	specialized instrument	high	high	100s of $	100s of $
Aircraft (mid altitude)	500	2	1	0.005	larger aircraft	specialized instrument	high	high	10s of $	100s of $
Aircraft (High altitude)	3,000	2	1	0.001	larger aircraft	specialized instrument	high	high	10s of $	10s of $
Drones (flux plane)	1	2	1	3.000	drone	Ppb sensitive analyzer	moderate	moderate	1000s of $\	10k's of $
Drones (OGI camera)	1	2	0.5	2.500	drone	OGI camera	moderate	moderate	1000s of $	10k's of $
Vehicles	12.5	2	1	0.240	vehicle	Ppb sensitive analyzer	moderate	moderate	100s of $	1000's of $
Continuous Emissions Monitoring Solutions										
CEMs (point sensor)	1	0	0.1	0.100		point sensor	low	high		10k's of $
CEMs (camera)	1	0	0.1	0.100		OGI camera	moderate	moderate		10k's of $
CEMs (open-path laser, single site)	1	0	0.1	0.100		long-path laser	high	moderate		10k's of $
CEMs (open-path laser, assume 10 sites covered)	10	0	0.1	0.010		long-path laser	high	moderate		10k's of $

Notes: Cost estimates consider only underlying, intrinsic, cost of deployment. Costs are approximate and intended to be illustrative only.
Analysis does not reference any specific solution.
Results do not include amortization of development costs, market, and maintenance.

Table 3-5. *Cost Drivers Underlying a Variety of Advanced Emissions Detection and Quantification Solutions*

operating or maintaining sophisticated systems in the field to instrumentation and analytics experts required to develop insights from collected data. Qualitative observations by operators and solution developers indicate a shortage of properly trained personnel for these roles.

The interest in appropriate training is evidenced by an uptick in attendance at methane emissions conferences and training courses for all aspects of these advanced technologies. For example, attendance at a recent day-long course on emissions modeling methods increased from 10 attendees in 2022 to more than 50 in 2023. Three recent workshops reviewing advanced systems conducted by the University of Texas at Austin drew hundreds of participants.

FINDING 14: Widespread deployment of advanced emissions detection and quantification solutions will require substantial numbers of trained personnel, and it is unclear that existing training programs are sufficient to meet this need.

D. Uncertainties in Emissions Detection and Quantification

There is a widespread consensus in industry and government on methods to handle uncertainty from traditional measurement technologies, such as flow meters, ambient air monitors, and similar measurement systems. In contrast, advanced emissions detection and quantification methods exhibit substantially higher single- and aggregated-measurement uncertainty. Additionally, these measurements may exhibit additional uncertainty issues, including bias in mean estimates or uncertainty, that depends upon environmental conditions or operator experience.[164, 165, 166, 167, 168, 169, 170] These uncertainties interact with sampling and response strategies and often require different statistical treatment than traditional measurement methods.[171, 172, 173, 174, 175]

As discussed in Section III, advanced technologies rely on complex analytics to convert sensor readings (typically low uncertainty) to emissions detections and quantifications (higher uncertainty). While uncertainties will reduce with additional development, uncertainties for advanced technologies are unlikely to reduce to levels commonly seen for traditional systems that measure emissions at the source. Therefore, for programs to utilize these data successfully, programs must adapt to the less-certain results produced by advanced technologies.

Current regulatory and voluntary reporting frameworks provide little guidance on analysis of uncertainty. Variations in how uncertainty is considered could have material impacts on methane fees, certified gas results, or enforcement actions. Ambiguity in the handling of uncertain data increases the risks of relying on advanced technologies and will impede adoption of those technologies. Examples include:

- Little guidance on how to incorporate uncertainty into data requirements for voluntary or regulatory reporting
- Little guidance on sampling sites for measurement and scaling strategies for reporting
- Using advanced technology estimates for regulatory enforcement, without an understanding of the quantification and localization uncertainties, may result in challenges to supporting enforcement actions.

Additionally, there is little guidance on how to compare results from multiple solutions, all of which have high uncertainty with complex

164 Bell, C., Vaughn, T., Zimmerle, D., Herndon, S., Yacovitch, T., Heath, G., Pétron, G., et al. 2017. "Comparison of Methane Emission Estimates from Multiple Measurement Techniques at Natural Gas Production Pads." *Elementa: Science of the Anthropocene* 5 (0): 79. https://doi.org/10.1525/elementa.266.

165 Ilonze et al. 2023.

166 Bell et al. 2023.

167 Brown et al. 2023.

168 Brown et al. 2023.

169 Conrad et al. 2023.

170 Sherwin et al. 2021.

171 Conrad et al. 2023.

172 Kunkel et al. 2023.

173 Sherwin et al. 2023.

174 Schissel et al. 2022.

175 Schissel et al. 2023.

dependencies. For example, basin-scale observations from satellites may be utilized to attempt to verify reporting from operators in a basin. If operators in that basin are using advanced technologies, both the operator reporting and the satellite results will have uncertainties that are highly dependent on deployment conditions in that basin and data analysis methods employed in the emissions estimation.

While numerous scientific studies have performed such comparisons,[176, 177, 178] handling of technology and methodological uncertainties remains a subject of substantial research.[179] In the absence of well-understood comparison methods, there is a risk of disagreement when evaluating the quality of emissions data across scales (Section IV).

FINDING 15: **Data from advanced emissions detection and quantification technology that make measurements remote from sources have larger uncertainties than traditional measurements that make direct measurements of emissions. Lack of guidance on the handling of those uncertainties may impede adoption and appropriate utilization of these technologies as powerful tools for quick detection and efficient mitigation.**

E. Physical Barriers to Implementation

Different site types and locations present unique challenges in scale-up and integration of advanced detection technologies. Current common barriers include:

1. Access to electrical power where continuous use of solar power is not sufficient. Many production sites, as well as smaller sites in midstream and distribution, are not connected to gridpower. While some sensor types can be effectively powered using solar panels, others require higher power levels that are impractical for distributed solar systems. Additionally, lack of available continuous solar power can be due to seasonal solar power fluctuations, the presence of canopy, or other similar locational challenges.
2. Access to communications infrastructure may be inadequate in some areas. Some production sites, as well as smaller sites in midstream and distribution, have inadequate communications infrastructure, restricting the speed of mitigation actions in response to emissions detections.
3. The size of sites—the area 'inside the fence line'—may be insufficient for some technologies that need to be positioned farther from equipment. Height or illumination restrictions may also impact the ability to deploy some technologies on some sites.
4. Recently, supply chain issues have impacted delivery of sensor systems for advanced methane detection technology.
5. Some sites require explosion-proof sensor systems (e.g., Class 1/Div. 1 certification); delays developing appropriate hardware and associated certification may impact scale-up of advanced technologies.

RECOMMENDATION 9: ***The NPC recommends that EPA issue clear guidelines on the criteria for approval of alternative fugitive emissions standards, make such a provision available to NSPS OOOOa/b/c-affected facilities, and expeditiously approve alternative technologies.***

RECOMMENDATION 10: ***The NPC recommends National Institute of Standards and Technology, American National Standards Institute, and the American Petroleum Institute (API) collaborate to develop and distribute standards, guidance, and/or recommended practices regarding methane emissions detection, measurement, and quantification and to describe the current readiness of available and relevant technologies. These documents should be developed in a way that allows them to be incorporated by reference into emissions regulations.***

176 Lyon et al. 2015.

177 Sherwin et al. 2023.

178 Peischl et al. 2015.

179 Zimmerle et al. 2023.

RECOMMENDATION 11: *The NPC recommends that federal agencies work with technology providers, operators, and others to develop consistent data interchange formats and to promote infrastructures such as communication capabilities that would promote deployments of advanced emissions detection and quantification systems.*

VIII. GLOBAL REACH AND COMPETITIVENESS

As discussed earlier in this chapter (see Section II), there are various domestic and global GHG emissions reporting programs. The different reporting programs allow comparison of GHG emissions among Industrial sectors, and/or countries within a single reporting program, but comparing information across programs can be challenging due to differences in how emissions are calculated. For example, the IEA provides an inventory of methane emissions on a global scale through the Global Methane Tracker (iea.org/data-and-statistics/data-product/methane-tracker-database-2023). The IEA estimates are different from the data reported by the United States to the UNFCCC Emissions Data (https://di.unfccc.int/time_series). GHG emissions inventories can also be assembled by a third-party service, for example, Climate TRACE (https://climatetrace.org/data). Their estimates of U.S. total emissions associated with the oil and natural gas sector can also differ.

IEA assumes that almost all national inventories are underreported. IEA also notes that a game changer in providing a more robust accounting of emissions is due to advances in monitoring technologies, especially from satellites. Current satellite data processing algorithms, while not without challenges as noted in this chapter, provide regional estimates of emissions over longer periods of time (see Section IV). Current IEA methods have not incorporated this regional estimation methodology.

FINDING 16: **To be applied consistently at global scales, methane emissions detection and quantification systems need to be applied at scale, providing information at hundreds of thousands of sites.**

The number and variety of emissions detection and quantification systems that have been deployed in North America (United States and Canada) is greater than elsewhere in the world. The dispersed and competitive nature of North American oil and natural gas production has fostered a diverse approach to advanced technology development, deployment, and testing. While other regions have not invested as heavily in the development of emissions detection and quantification, increasing global trade in natural gas (pipeline and LNG) and focus on GHG emissions have driven demands for globally consistent emissions MMRV systems.[180]

With extensive experience in deploying MMRV systems, the United States is well positioned to lead in improving these systems at the global level. The DOE has taken a leadership role in organizing a coalition of natural gas importing and exporting counties to establish a global framework for MMRV GHG emissions from natural gas supply chains (https://www.energy.gov/fecm/articles/doe-announces-global-collaboration-reduce-methane-emissions). There will be multiple challenges associated with this effort, including variability in emissions reporting, variability in the availability and transparency of measurements and measurement interpretation methods, and lack of trained personnel to implement programs. Ravikumar et al.,[181] have outlined the types of technical challenges that will need to be addressed. Nevertheless, monitoring, measuring, reporting, and verifying GHG emissions from natural gas systems will be one of the first MMRV systems to be tested for a globally traded product with complex supply chains. The precedents established using this system could define pathways for multiple types of MMRV systems going forward.

180 Ravikumar, A., Tullos, E., Allen, D., Cahill, B., Hamburg, S., Zimmerle, D., Fox, T., et al. 2023. "Measurement-Based Differentiation of Low-Emission Global Natural Gas Supply Chains." *Nature Energy* 8 (11): 1174–76. https://doi.org/10.1038/s41560-023-01381-x.

181 Ravikumar et al. 2023.

Additionally, the United States is a signatory to the Global Methane Pledge, a voluntary effort by 150 countries to reduce global methane emissions by at least 30% from 2020 levels by 2030. MMRV and advanced technology deployment experience could be a key United States contribution to global efforts to reduce emissions under this pledge.

RECOMMENDATION 12: *The NPC recommends the DOE improve the efficiency and transparency of multiscale methane emissions monitoring of the global energy sector by promoting harmonization of reporting methods and measurement approaches.*

IX. SUMMARY

Detection and accurate, quantitative tracking of the GHG emissions from oil and natural gas supply chains is an important element in making progress toward climate goals. Tracking of carbon dioxide emissions is primarily based on fuel consumption and emissions estimates are generally viewed as reliable. In contrast, methane emissions can be challenging to detect and quantify due to the diverse nature and sources of the emissions. The capabilities of methane emissions detection and quantification systems have expanded rapidly over the last decade and are continuing to expand rapidly, in part due to previous support from the DOE. Approximately a decade ago, measurements of methane emissions were sparse, difficult, and expensive. Today, as shown in Figure 3-11, a wide variety of measurements and observation platforms (fixed sites, ground vehicles, drones, aircraft, and satellites) are available and are generating large data volumes globally.

Generally, current methane emissions detection and quantification systems provide estimates of emissions by (i) making periodic measurements of methane concentration remote from a source; (ii) using various types of atmospheric data and models to convert methane concentrations into an emissions rate; and (iii) extrapolating these, frequently short-duration, estimates of emissions rates into an annual or other long-term estimates. Technical capabilities need to be expanded in all three of these areas, including support for consistent data analysis methods and systems approaches to enable intercomparison of data

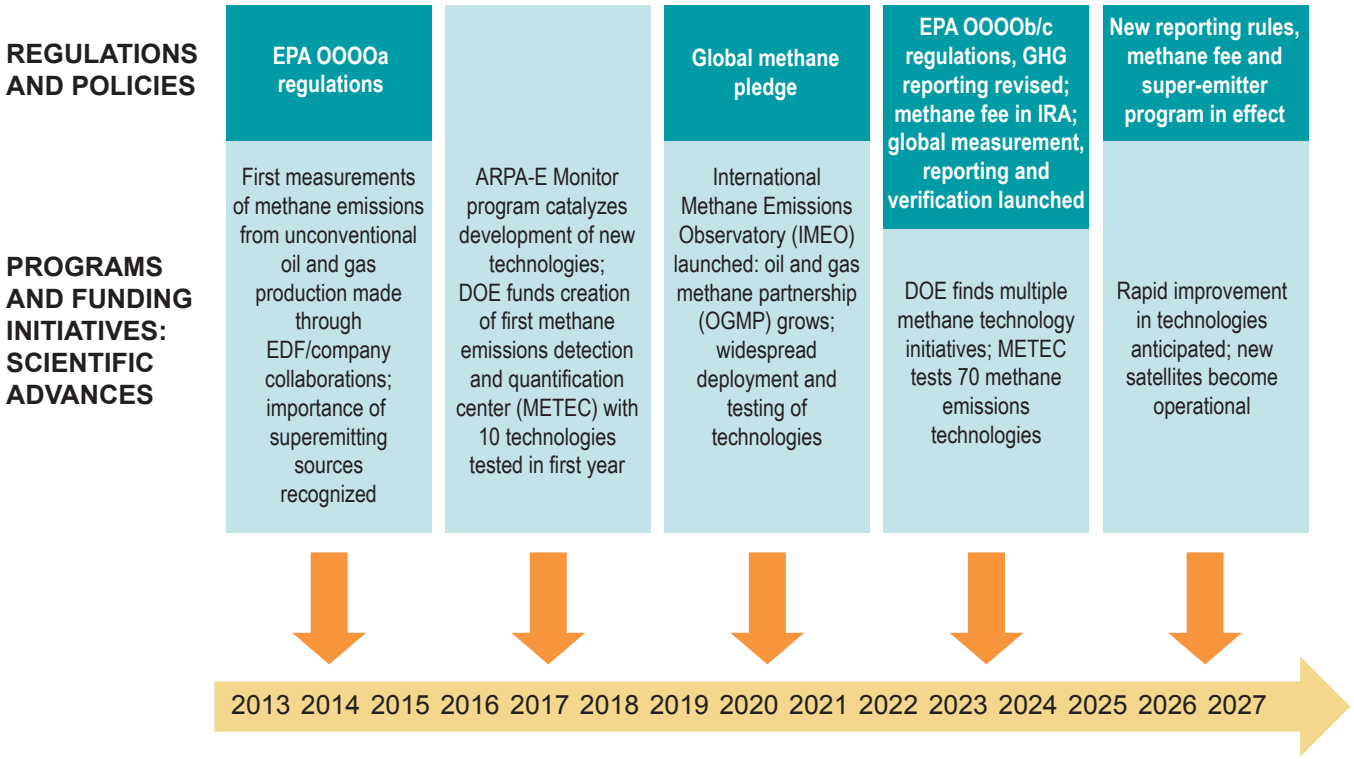


Figure 3-11. *Methane Emissions Capabilities, Regulations, and Policies Evolution*

from different technologies. Technology evaluation centers, which have been highly successful in evaluating the performance of methane emissions detection and quantification systems also need to be expanded. Finally, given the historical and expected evolution in methane emissions detection and quantification technologies, advances will need to be regularly and rapidly reviewed to facilitate the use of these technologies in regulatory applications. All three of these elements—improved measurement systems, robust testing capabilities, and evolving use of technologies in regulation and policy—are necessary for continued advancement of technologies.

This chapter has made detailed findings and recommendations for the improvement of emissions detection and quantification technologies, which can be summarized under the following four overarching findings and their associated summary recommendations.

- Continued investments in methane emissions detection and quantification systems are needed to improve the accuracy of emissions estimates.
- Information from emissions detection and quantification systems needs to be actionable; combining this information with operational data and systems will maximize its utility.
- Methane emissions detection and quantification systems need to be applied at scale, providing information at hundreds of thousands of sites.
- Rapidly evolving emissions detection and quantification systems need to be integrated into public and private decision-making.

OVERARCHING FINDING 1: Continued investments in methane emissions detection and quantification systems are needed to improve the accuracy of emissions estimates.

RECOMMENDATION 13: *The NPC recommends the DOE and other governmental organizations continue supporting the development and use of emissions detection and quantification technologies that are accurate and cost-effective, produce actionable information that is internationally harmonized, and can be deployed in a variety of environments (onshore, offshore, upstream, midstream, downstream) in various climates and topographies. Geographically diverse technology evaluation centers should be created, capable of testing technologies in situations representative of multiple segments of natural gas supply chains, and the evolution of the state of technology development should be tracked and reported on annually to facilitate their incorporation into regulation and policy.*

OVERARCHING FINDING 2: Information from emissions detection and quantification systems needs to be actionable; combining the emissions information with operational data and systems will maximize its utility.

RECOMMENDATION 14: *The NPC recommends the DOE fund the improvement of site/facility-scale data resources used in the public attribution of emissions sources.*

RECOMMENDATION 15: *The NPC recommends the DOE continue to support technology innovations to reduce cost and improve the effectiveness of next-generation, low-emitting facilities across multiple supply chain sectors that integrate emissions detection and quantification systems with other monitoring and data collection systems. Innovations include, but are not limited to, development of predictive emissions monitoring systems and machine learning systems for data analysis, targeted metering, and process sensing/monitoring systems.*

OVERARCHING FINDING 3: Methane emissions detection and quantification systems need to be applied at scale, providing information at hundreds of thousands of sites.

RECOMMENDATION 16: *The NPC recommends the DOE improve the efficiency and transparency of multiscale methane emissions monitoring of the energy sector, from handheld devices to satellites, by continuing to sponsor public-private and global partnerships and making measurements across multiple scales.*

RECOMMENDATION 17: *The NPC recommends the DOE and other governmental organizations support the development of dense networks of meteorological measurement stations in regions likely to be targets for localized and wide-area (local ground campaigns through satellite observations) detection and measurement of methane emissions. Spatially dense, vertically, and horizontally resolved, and temporally high frequency measurement of wind velocity (i.e., speed and direction) is a priority.*

RECOMMENDATION 18: *The NPC recommends that federal agencies work with technology providers, operators, and others to develop consistent data interchange formats and to promote infrastructures such as communication capabilities that would promote deployments of advanced emissions detection and quantification systems.*

OVERARCHING FINDING 4: Rapidly evolving emissions detection and quantification systems need to be integrated into public and private decision-making.

RECOMMENDATION 19: *The NPC recommends the DOE work with the EPA and other agencies to improve the processes for incorporating advanced detection and quantification technology as part of regulatory requirements. The use of information from other available state and national programs to inform the revision of EPA and other agency requirements could improve the timeline and effectiveness of these processes.*

Chapter 4

GREENHOUSE GASES LIFE CYCLE ASSESSMENT FOR NATURAL GAS AND LIQUEFIED NATURAL GAS

OVERVIEW

Life cycle assessment (LCA) is a well-researched and long-standing set of methods for estimating potential environmental impacts of products, including energy products such as natural gas. Among the potential environmental impacts of natural gas, climate change driven by greenhouse gas (GHG) emissions has received the most attention in the field of LCA research.

LCAs of natural gas or liquefied natural gas (LNG) may be used to estimate the GHG impacts over all or part of their supply chains, including production, processing, transportation, distribution or liquefaction, shipping, regasification, and end use. It allows for consistent comparison among options that provide the same function to credibly inform decision-makers and stakeholders about choices, such as choices between policies oriented toward reductions in carbon dioxide (CO_2) emissions versus policies oriented toward reductions in methane (Ch_4) emissions.

This chapter introduces the fundamental concepts of LCA, discusses modeling GHG emissions from U.S. natural gas and LNG supply chains, quantifies life cycle GHG emissions, and explores application of LCAs in public and corporate policies. The study presents new research from a review and harmonization (meta-analysis) of recent LCA studies and develops a new, streamlined LCA model (SLiNG-GHG: streamlined LCA of natural gas–greenhouse gases) to support screening-level life cycle estimates of the carbon footprints (CFPs) across the natural gas and LNG supply chains.

In this chapter, results of GHG-focused LCAs of natural gas are presented using the 100-year global warming potentials (GWP100) used by the U.S. Environmental Protection Agency's (EPA) annual greenhouse gas inventory (GHGI) and for United Nations Framework Convention on Climate Change reporting. Results of GHG-focused LCAs are also presented using 20-year global warming potentials (GWP20).

This chapter also addresses harmonization of LCAs, which provides perspective on the consistency of published estimates of life cycle GHG emissions for U.S. natural gas development based on a systematic review of published literature. Past LCAs differ in system boundaries, modeled stages of the natural gas supply chain, temporal vintage of input data, units of published results, and other technical decisions (e.g., GWPs), which makes comparison of "as published" results between different studies difficult. More than 2,220 LCAs were subjected to several successive screens, employing both quantitative and qualitative objective criteria. After screening, the process of harmonization adjusts published results to ensure greater consistency in LCA methods such that estimates of life cycle GHG emissions are more commensurable. Harmonization provides value by clarifying central tendency in prior published estimates that then can be used directly by decision-makers or in derivative analyses.

Building on the learnings from the harmonization process, the study developed a streamlined LCA model (SLiNG-GHG) that provides screening-level life cycle GHG emissions estimates from natural gas and LNG supply chains. It uses publicly available key model inputs developed from a combination of published literature, study member expert judgment, and external LCA modeling

teams. The purpose of the SLiNG-GHG model is to provide a reasonable, transparent, easy to use, and publicly available screening-level estimate of life cycle GHG emissions for natural gas and LNG supply chains. The study compares the results from the model to those produced independently by external modeling teams for similar scenarios and pathways for both domestic natural gas and LNG supply chains as a form of model validation. The model has been successfully demonstrated using a range of inputs, including national scale, default inputs, and user-defined regional and future scenario inputs, as well as measurement-based ones. Two sensitivity case studies were also conducted that leverage recent methane emissions measurements. A model educational website is available with source code, a user manual, and visualization of key results.

The study reviews the current and expected future use of LCAs in federal and state policy, as well as in corporate policies. There is growing interest in the use of LCAs across many types of stakeholder groups.

Finally, the study proposes a framework for robust incorporation of emissions measurement data into LCAs, where practical and applicable, addressing a key challenge that should allow LCAs to be used confidently going forward.

I. INTRODUCTION TO LIFE CYCLE ASSESSMENT (LCA)

In the public discussion of the potential environmental impacts of natural gas and LNG, a variety of topics arise, including hydraulic fracturing, methane emissions, pipelines, and CO_2 emissions associated with the combustion of natural gas (e.g., at power plants). The potential environmental impacts associated with natural gas may occur across the supply chain in a variety of ways.

LCA[1] is a rigorous method of estimating these potential impacts. In practical terms, LCA is a technique for estimating the potential environmental impacts of a product or service over all or part of its life cycle (often referred to as cradle to grave or cradle to gate), including procurement of raw materials, manufacturing activities, use of the product, and the end-of-life disposal. These impacts may include GHG emissions, energy use, water consumption, and waste, among other impacts.[2] By considering a comprehensive set of impacts of a product in this way, one avoids burden shifting of environmental impacts from one phase of a product life cycle to another.[3] LCA also facilitates understanding of how specific operations within the phases of a product life cycle contribute to the product's overall environmental impact.[4]

An LCA must account for as much of the supply chain as possible. In this study, the term supply chain refers to the set of individual stages (or operational processes) of the natural gas or LNG system boundary (see Figure 4-1 as an example). The term supply chain is also used to refer to specific physical flow paths in the natural gas supply chain (e.g., Appalachia to Gulf Coast). The sum of GHG emissions associated with a single process within the life cycle of natural gas or any coproduct of that process does not constitute an LCA. Furthermore, an environmental impact statement for a particular project or facility is not an LCA.

The concepts underlying LCA were initially developed in the 1970s[5] and advanced in subsequent decades. It was standardized in 1997 with the publication of *International Organization for Standardization (ISO) 14040* and in 2006 with the publication of *ISO 14044*. Subsequently, *ISO*

1 LCAs are sometimes referred to as life cycle analyses. In this study, NPC uses LCA consistent with ISO guidelines.

2 United Nations Environment Programme Life Cycle Initiative: https://www.lifecycleinitiative.org/starting-life-cycle-thinking/life-cycle-approaches/environmental-lca/.

3 Algunaibet, Ibrahim M. and Gonzalo Guillén-Gosálbez. "Life Cycle Burden-Shifting in Energy Systems Designed to Minimize Greenhouse Gas Emissions: Novel Analytical Method and Application to the United States." *Journal of Cleaner Production*. Vol. 229, 2019, Pages 886-901. https://doi.org/10.1016/j.jclepro.2019.04.276.

4 United Nations Environment Programme Life Cycle Initiative. "Life Cycle Assessment: A Product-Oriented Method for Sustainability Analysis." n.d. www.life cycleinitiative.org/wp-content/uploads/2013/06/Module-f-Interpretation.pdf.

5 Guinée, J.B., Heijungs, R., Huppes, G., Zamagni, A., Masoni, P., Buonamici, R., Ekvall, T., and Rydberg, T. 2011. "Life Cycle Assessment: Past, Present, and Future." *Environmental Science & Technology*. 45 (1): 90–96. https://doi.org/10.1021/es101316v.

6 ISO 14044 International Standard. Environmental Management-Life Cycle Assessment–Principles and Framework. International Organization for Standardization. Geneva, Switzerland. 2006. https://www.iso.org/obp/ui/#iso:std:iso:14044:ed-1:v1:en.

14067[7] was released, providing clear requirements and guidelines for estimating CFPs of products, while also aligning with data used for GHG emissions reporting standards (ISO14064). It should be noted that ISO guidelines are general enough to be applicable to a wide variety of products and services. ISO does not define a single method for conducting an LCA of natural gas or any other product, but outlines principles, frameworks, and requirements.

A. LCA Process

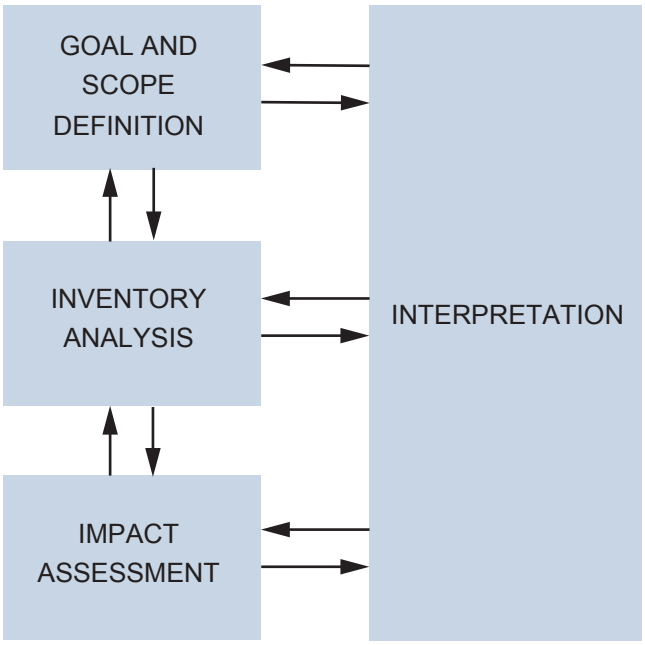
ISO 14044 defines the phases of an LCA investigation as follows:

1. **The goal and scope definition phase:** In the goal and scope phase, the system boundary and level of detail are defined in accordance with the intended use of the study and its results.
2. **The life cycle inventory analysis phase (LCI):** In the LCI phase, data (such as operations data) are collected directly, or from databases, to define material, energy, and environmental flows into and out of individual facilities along the product's life cycle. These flows may be connected via material or energy balances to ensure mass or energy conservation throughout the product's life cycle. The use of material and energy balances ensures that environmental impacts (e.g., GHG emissions) and the relative flows of material, energy, and emissions are appropriately scaled to the amount of the product being assessed.
3. **The life cycle impact assessment phase (LCIA):** In the LCIA phase, energy and resource use, or emissions to air or water, are also translated to environmental impact metrics using impact assessment methods, such as global warming potentials (GWP). Those metrics are normalized by a metric defining the function of the product (functional unit).
4. **The interpretation phase:** Normalization of environmental impacts by the function of a product is a distinctive feature of LCA and allows for comparisons and interpretation of the results between products on a functional basis.

The process of LCA is represented in Figure 4-1.

Key to this procedure are the following definitions, provided in *ISO 14040* and *14044*:

1. **System boundary:** set of criteria specifying which unit processes are part of a product system
2. **Process:** set of interrelated or interacting activities that transform inputs into outputs
3. **Unit process:** smallest element considered in the life cycle inventory analysis for which input and output data are quantified
4. **Product system:** collection of unit processes with elementary flows and product flows performing one or more defined functions, and which model the life cycle of a product



Source: ISO 14044 International Standard. Environmental Management-Life Cycle Assessment–Principles and Framework. International Organization for Standardization. Geneva, Switzerland, 2006, https://www.iso.org/obp/ui/#iso:std:iso:14044:ed-1:v1:en.

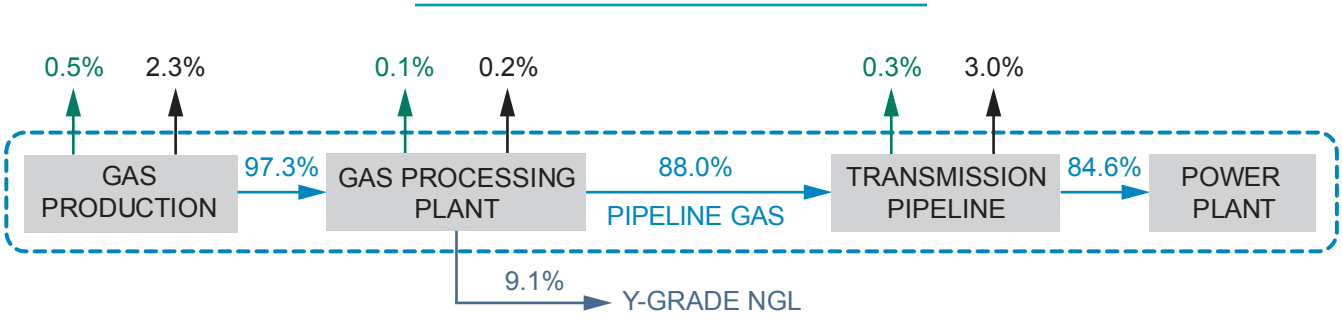
Figure 4-1. *The General Methodological Framework for Life Cycle Assessment (LCA), Adapted from ISO 14044*

7 ISO 14067 International Standard. Greenhouse Gases–Carbon Footprint of Products–Requirements and Guidelines for Quantification. International Organization for Standardization. Geneva, Switzerland. 2018. https://www.iso.org/standard/71206.html.

5. **Elementary flow:** material or energy entering the system being studied that has been drawn from the environment without previous human transformation, material, or energy leaving the system being studied that is released into the environment without subsequent human transformation
6. **Intermediate flow:** product, material, or energy flow occurring between unit processes of the product system being studied
7. **Product flow:** products entering from, or leaving to, another product system
8. **Coproduct:** any of two or more products coming from the same unit process or product system
9. **Functional unit:** quantified performance of a product system for use as a reference unit

These concepts are illustrated in Figure 4-2. In this example, the natural gas system boundary is defined as the collection of operations specific to natural gas from well to wire. The elementary flow is the raw natural gas from the well, which must be processed to meet the specifications of natural gas consumers. Unit processes in the gas production phase of the life cycle include: (a) many well pads, where liquids and gas are separated; (b) gathering pipelines, which connect well pads to compressor stations; and (c) compressor stations, which move gas from the well pads to the gas plant. At the gas processing plant, the raw gas is separated into two coproducts: pipeline quality gas (residue gas) and Y-grade or unfractionated natural gas liquids (NGLs). The NGLs then leave the natural gas LCA system boundary. Unit processes in this phase may include the cryogenic gas plant and a compressor, which increases the pressure of the residue gas to that of the pipeline. Unit processes in the transmission pipeline phase of the gas life cycle may include one or more compressor stations between the gas plant and the final destination of the gas. The end of the gas life cycle is, in this case, a power plant. Collectively, these processes constitute the product system in the natural gas supply chain.

The study notes that, by themselves, the unit processes illustrated above within each stage of the natural gas supply chain (Figure 4-2) have notably different throughputs. The flow of gas from an individual well pad is considerably lower than that through a compressor station because a compressor station gathers gas from many wells. Furthermore, many processing plants (operated by many companies) may feed an intra- or interstate transmission pipeline. Thus, one may not simply add up the emissions associated with several facilities in a geographical area and normalize these emissions by an estimate of gross production in that area. As previously discussed, LCA practitioners must normalize the inputs and outputs of each unit process regarding key product flows to yield multiple inventories for each unit process, and then integrate those inventories via material and energy balances. This ensures that



Notes: Fractions of gross hydrocarbons produced are as follows: Figures in green represent gas that is vented, or otherwise noncombustion emissions. Figures in black represent gas that is combusted and emitted. Figures in light blue represent the flow of natural gas from one phase to another. In this example, 9.1% of gross production is NGLs, which leave the natural gas system boundary. Note that 1 MMscf of natural gas produced at the well pad is not equivalent to 1 MMscf of natural gas delivered to the customer due to consumptive losses, emissions, and separation of NGLs.

Source: Fractions of gross production reported here are adopted from the peer-reviewed LCA of Marcellus natural gas (Mallapragada et al., 2018, https://doi.org/10.1016/j.jclepro.2018.09.111).

Figure 4-2. *Example of a Natural Gas LCA System Boundary for Marcellus Natural Gas*

mass is conserved and potential environmental impacts are correctly accounted for.

B. Functional Unit

As previously mentioned, a key concept in LCA is that of the functional unit. The functional unit is the denominator for life cycle environmental impacts and is defined in terms of how a product is *used*. It is the reference flow by which all emissions are scaled (normalized). It is also key to comparing alternative products. Choice of functional unit will typically be defined in the goal and scope phase of an LCA study because it will serve as the basis for how the study will be used.

For example, if the environmental performance of the natural gas system illustrated in Figure 4-2 were to be compared with the life cycles of one or more types of coal, it would not be appropriate to compare the two types of fuels on a basis of one million Btu of fuel delivered because the energy efficiency of the end-use power plant is not fully accounted. The generation of power from coal requires "on average about one-third more energy than producing [power] from natural gas."[9] Thus, an appropriate functional unit for the comparison of coal to natural gas may be "Megawatt-hours of power generated" from the fuel arriving at its power plant.[10]

On the other hand, a functional unit of one million Btu of fuel delivered *may* be appropriate for comparing two sources of natural gas (e.g., gas produced from two different geological basins) potentially delivered to the same customer, since the end use of the gas would be the same. It is critical, however, to specify what is meant by a Btu of fuel. Fuels are often expressed in terms of lower heating values (LHVs) and higher heating values (HHVs). For natural gas, the difference between HHV and LHV is about 10%. Thus, when comparing the life cycle impacts of different sources of natural gas, care must be taken to ensure that the carbon intensities are expressed on the same basis.

C. Allocation and Coproducts

Coproduct allocation of impacts between gas, liquids, and oil produced from the same well was documented as far back as 2013, where Jordaan et al., compared a gas-to-liquids scenario against other potential oil substitutes for the United States. Through their investigation of the Eagle Ford Shale play, Chen et al., also noted the importance of "performing disaggregated emission allocation" ("Option 1a" in the ISO guidelines) when quantifying life cycle emissions of associated gas (i.e., gas that is coproduced with oil). This is due to the potential interconnectedness of the oil and gas system. Allen et al., highlights the importance of emissions allocation and concluded that differences in the emissions allocation methods can result in differences that are comparable to difference in combustion emissions between coal and natural gas. The complexity of such systems is illustrated in Figure 4-3, where each gray box represents a unit process.

In the natural gas life cycle illustrated in Figure 4-2, two salable products leave the gas processing phase of the life cycle: pipeline quality gas and NGLs. Allocation of environmental impacts to coproducts originating from a common process or supply chain is addressed by *ISO 14040* as follows:

- Wherever possible, allocation should be avoided by:
  - dividing the unit process to be allocated into two or more subprocesses and collecting the

8 One British Thermal Unit (Btu) is approximately equal to 1,055 Joules.

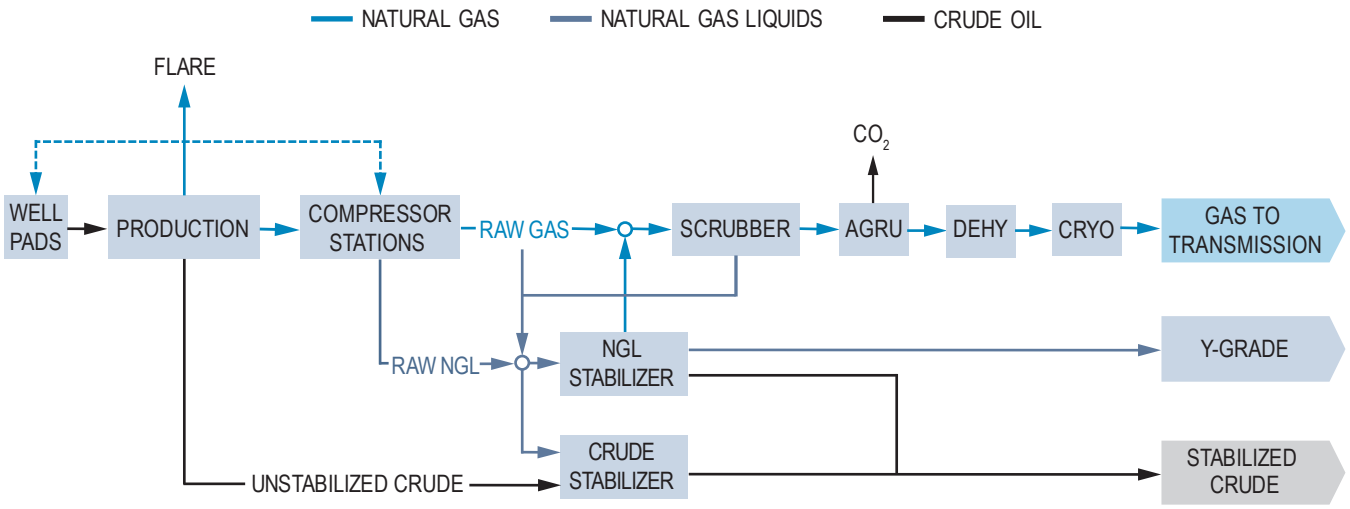
9 EIA. "Electric Power Sector CO2 Emissions Drop as Generation Mix Shifts from Coal to Natural Gas." *Today in Energy*. June 9, 2021. https://www.eia.gov/todayinenergy/detail.php?id=48296#:~:text=In%202019%2C%20the%20conversion%20efficiency,electricity%20in%20the%20United%20States.

10 EIA. "Glossary - U.S. Energy Information Administration (EIA)." n.d. https://www.eia.gov/tools/glossary/index.php?id=H.

11 Jordaan, S.M., Diaz Anadon, L., Mielke, E., and Schrag, D.P. 2013. "Regional Water Implications of Reducing Oil Imports with Liquid Transportation Fuel Alternatives in the United States." *Environmental Science & Technology* 47 (21): 11976–84. https://doi.org/10.1021/es404130v.

12 Chen, Q., Dunn, J.B., and Allen, D.T. 2019. "Aggregation and Allocation of Greenhouse Gas Emissions in Oil and Gas Production: Implications for Life-Cycle Greenhouse Gas Burdens." *ACS Sustainable Chemistry & Engineering* 7 (20): 17065–73. https://doi.org/10.1021/acssuschemeng.9b03136.

13 Allen, D.T., Chen, Q., and Dunn, J.B. 2021. "Consistent Metrics Needed for Quantifying Methane Emissions from Upstream Oil and Gas Operations." *Environmental Science and Technology Letters* 8 (4): 345–49. https://doi.org/10.1021/acs.estlett.0c00907.7



Notes: Allocation of GHG emissions in complex systems such as these may require more complex mathematical treatment to avoid allocating emissions from gas-specific equipment to oil and NGL, and vice versa. The compressor stations shown here are part of the gathering and boosting network, as defined in this chapter.

Source: Adopted from Contreras et al., 2021, https://doi.org/10.1016/j.jclepro.2021.129530.

Figure 4-3. *System Producing Oil, Gas, and NGLs*

input and output data related to these subprocesses (Partitioning)

- expanding the product system to include the additional functions related to the coproducts (System Expansion)

- Allocating the inputs and outputs of the system between its different products or functions in a way that reflects the underlying physical relationships or other relationships between them, with a preference for physical relationships (Allocation)

Establishment of a CFP specific to natural gas precludes "expanding the product system" (1b), but options (1a) and (2) have relevance to LCAs of natural gas. For example, crude oil and natural gas are often coproduced from the same well pad, and share some infrastructure, as shown in Figure 4-3. Both the raw gas and unstabilized crude flows leave the production box. By dividing the unit process into smaller subprocesses, allocation may be avoided. But in some instances, emissions may still need to be allocated between coproducts. For example, in the system illustrated in Figure 4-2, natural gas constitutes 81% of the mass leaving the gas processing plant *as products*, and 82% of the energy. If mass allocation were to be employed, then 81% of the emissions associated with the gas production and processing phases would be attributed to the natural gas that goes to the transmission pipeline, and 19% of the emissions associated with the gas production and processing phases would be ascribed to the NGLs.

In the majority of LCAs of energy products that have explicitly considered coproducts, allocation by energy content is the preferred approach, even though Y-grade NGLs predominantly serve as feedstocks for chemical plants in the U.S. and are not "energy products" per se. Ultimately, *ISO 14044* requires that a sensitivity analysis be conducted when several alternative allocation procedures seem applicable, thereby illustrating the consequences of the departure from the selected approach.

As a final note, ISO clearly specifies that environmental emissions flows may only be allocated to *products*, not *wastes*. Thus, if a natural gas treatment and processing plant were to produce three outputs, in the form of natural gas, NGL, and sulfur, and the sulfur was disposed as a waste, then GHG emissions associated with the gas plant and operations upstream of it should be allocated to natural gas and NGL only. In this case, GHG emissions associated with the disposal of sulfur should also be allocated to natural gas and NGL.

Similarly, emissions or other environmental impacts should not be allocated to produced water when it is injected into Class II disposal wells.

The ONE Future Methane Emissions Estimation Protocol[14] and the Natural Gas Sustainability Initiative Methane Emissions Intensity Protocol[15] offer support guidance on allocating emissions to coproducts in the natural gas supply chain.

D. Carbon Footprint

Since 2006, *ISO 14040* and *14044* have been supplemented with *ISO 14067*,[16] which establishes guidelines and requirements for the CFPs of products. An LCA exclusively investigating GHG emissions associated with a product yields a CFP. In other words, *ISO 14067* adopts the guidelines of *ISO 14044* but limits the scope of environmental impact assessment (the LCIA phase) to the climate change category (characterized by the use of GWPs). Thus, CFPs are expressed in terms of a functional unit of the product.[17]

The most recent version of *ISO 14067* specifically states:

- In the LCIA phase of a CFP study, the potential climate change impact of each GHG emitted and removed by the product system shall be calculated by multiplying the mass of GHG released or removed by the 100-year GWP given by the Intergovernmental Panel on Climate Change (IPCC) in units of kg CO_2e per kg emissions (with carbon feedbacks, according to IPCC)...
- Where GWP values are amended by the IPCC, the latest values shall be used in the CFP calculations if not otherwise stated and justified...
- GWP for other time horizons ..., as given by the IPCC, may be used in addition to GWP100 but should be reported separately.

In this report, unless otherwise specified, the study utilizes the GWPs for methane and nitrous oxide (N_2O) from the Fifth Assessment Report of the IPCC (AR5) to be consistent with the EPA's move to AR5 for GHG emissions reporting and accounting.[18]

ISO 14067 also introduces the concept of a partial CFP of a product, defined as:

- Partial carbon footprint: sum of GHG emissions and GHG removals of one or more selected process(es) in a product system expressed as CO_2 equivalents and based on the selected stages or processes within the life cycle[19]

For natural gas, a system boundary defining a partial CFP might include all operations associated with natural gas drilling and well completion (including hydraulic fracturing), through transportation of the gas to the end user (e.g., a power plant), but exclude the end use of the gas. This is also often referred to as a cradle-to-gate assessment, implying an LCA in which the supply chain is truncated at some point and does not consider the end use of the gas. This study reviews partial CFP beginning with production for three boundaries, or gates, along the natural gas supply chain: (1) interstate transmission, (2) local distribution company, and (3) up to the point of LNG delivery via ocean vessel to a regasification facility. The study does not include emissions from operations after these gates, including emissions from end-use consumption of the natural gas.

Besides key considerations in relation to functional units and coproduct allocation, the following are additional considerations in relation to natural gas LCAs for GHGs (or CFPs).

14 "Methane Emissions Estimation Protocol." August 3, 2016. Updated August 27, 2018, and August 3, 2020. https://onefuture.us/wp-content/uploads/2020/09/ONE-Future-Methane-Intensity-Protocol_V3_3Aug2020.pdf.

15 American Gas Association. "NGSI Methane Emissions Intensity Protocol." February 2021. https://www.aga.org/wp-content/uploads/2022/12/ngsi_methaneintensityprotocol_v1.0_feb2021.pdf.

16 ISO 14067 International Standard. Greenhouse Gases – Carbon Footprint of Products – Requirements and Guidelines for Quantification. International Organization for Standardization. Geneva, Switzerland, 2018. https://www.iso.org/standard/71206.html.

17 See Section I.B Functional Unit for further detail.

18 EPA. 2023. "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021." https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2021.

19 ISO 14067 International Standard. Greenhouse Gases – Carbon Footprint of Products – Requirements and Guidelines for Quantification. International Organization for Standardization. Geneva, Switzerland, 2018. https://www.iso.org/standard/71206.html.

E. Other Considerations in LCAs

1. Assessment of Data Quality

The quality of data used as an input into an LCA study is critical when assessing the results of a study. Data sources in LCA are generally referred to as primary or secondary, with primary data being collected and used specifically with the scope of a particular study (e.g., measurements of emissions for a specific compressor station), and secondary data coming from any other source (e.g., from a database of LCIs for a particular process such as natural gas compression).

In these cases, it is preferred to incorporate primary data than secondary data, where practical and applicable, and data from the same location as the system than a sourced from another part of the world.

2. Data Granularity and Supply Chain Representativeness

As previously discussed, there are various aspects of a study's data relevance that can be assessed in support of its overall representativeness. A key aspect is how the data used in the model aligns with the scope of the study. Most models approximate the emissions profile of their supply chain by using input data representative of the temporal and spatial boundary being examined. Data may be very aggregate (e.g., national-level average estimates of emissions or energy use associated with drilling or production operations) or they may be very granular (e.g., data pertinent to the production techniques and practices used for drilling specific wells). When the data are very granular, it will generally be able to better represent specific projects. On the other hand, studies using national average data may be suitable for focusing on the performance of the U.S. natural gas system as a whole without offering specific insights into potential reductions in emissions for the specific supply chain being assessed. For LCAs of natural gas there are various stages across the supply chain where the matching of appropriate data and scope are relevant. *The level of data granularity should be matched to the goal and scope of the LCA study.* Similar effects would be expected when using data assessing equipment performance.

3. Temporal Boundaries in LCA

System boundaries in LCA may have spatial and temporal dimensions. Often, the temporal system boundary is not clearly or explicitly defined/identified. An LCA of natural gas will typically include emissions associated with isolated events in the natural gas life cycle, such as those associated with drilling and completion of a well. However, other transient events may be challenging to quantify, as expected events may take place in the future, or not at all. The rate of production of a well may change in an unforeseeable way years after a reservoir engineer makes initial forecasts. Improvements in technology may abrogate emissions that would not be foreseeable at the time an LCA was conducted. It is generally expected that construction emissions and end-of-life emissions, if applicable, be levelized across the LCA study period to apportion one-time or nonroutine operating emissions across the volume of product produced within the LCA study period. Utilizing emissions and other data exclusively occurring during a specific year of operations may yield results that are not reflective of the life cycle of an oil and gas project. However, CFPs estimated using data collected in this fashion may yield insight into the annual performance of the products resulting from that project.

4. Variability and Uncertainty

In the context of this study, it may be difficult to assess the overall impact of delivered gas employing national-level datasets because known regional differences in production (e.g., dry gas production versus associated gas), use of different types of equipment (e.g., compressor turbines versus reciprocating internal combustion engines), and transmission pathways (e.g., lengths of pipelines, whether gas is stored and in what type of facility or formation). As such, results from studies of the impacts of U.S. average gas may lead to ranges of results, in part due to both uncertainty and variability. The results may be expressed as uncertainty/error bars, distributions, or others statistical metrics. Comparisons of results from different methods may require more than just comparing average values and may require assessments of differences in ranges and/or distributions. Additional discussions on uncertainties can be found Section V.B.5.b

("Uncertainty Quantification in Measurement-Informed LCAs") of this chapter.

The GHG emissions from the natural gas supply chain come from multiple sources arising from routine operations, occasional events, intentional flaring or venting, and fugitive emissions. The ways in which these emissions sources vary among different locations, operators, and stages of the supply chain result in life cycle GHG emissions with wide uncertainty. Figure 4-4, adapted from National Energy Technology Laboratory's (NETL) life cycle study for ONE Future, exemplifies the GHG emissions uncertainty, and hence supply chain variability and complexity. Figure 4-4 illustrates the NETL breakdown of GHG emissions associated with U.S. natural gas in 2017.

Additional considerations are outlined in Appendix E-14.

Figure 4-5 demonstrates how an estimate of the CFP of national average natural gas can obscure unique emissions profiles for gas from regions or specific natural gas types. This figure compares equipment-level emissions for the U.S. average (using the production-stage results illustrated in Figure 4-4) to the same emissions sources for gas from Appalachian Shale and conventional Permian resources.[20]

The regional results do not necessarily follow the emissions profile of the national average. For example, NETL estimated emissions associated with intermittent bleed pneumatic devices at the national level to be approximately six times greater than those associated with natural gas from Appalachian Shale, but approximately half of those associated with conventional Permian gas. NETL also estimated that emissions associated with liquids-unloading emissions are comparable between the national average and Appalachian Shale but are markedly lower for conventional natural gas from the Permian. The study notes that the NETL investigations of natural gas from the United States as a whole, the Appalachian basins (Marcellus, Utica), or the Permian Basin, are not necessarily representative of any individual operator or all operators in 2017, or even today. This illustrates that each oil and gas resource may have a unique emissions profile based on heterogeneous operating practices, reservoir features, etc., and the construction of a national average may obscure important emissions reduction opportunities.

F. LCAs and Alternative Emissions Reporting Processes and Metrics

There are various emissions reporting frameworks complementary to LCA, serving various similar stakeholder-specific purposes. Although data collection and management strategies for LCA may be similar for other frameworks, LCA is the only method that estimates the environmental impact of a product relative to its *function*, allowing for comparison with other products. These are typically referred to as activity-based approaches and GHG emissions inventories can be either production (direct) or emissions consumption (indirect).[21]

1. GHG Protocol (Scope Reporting)

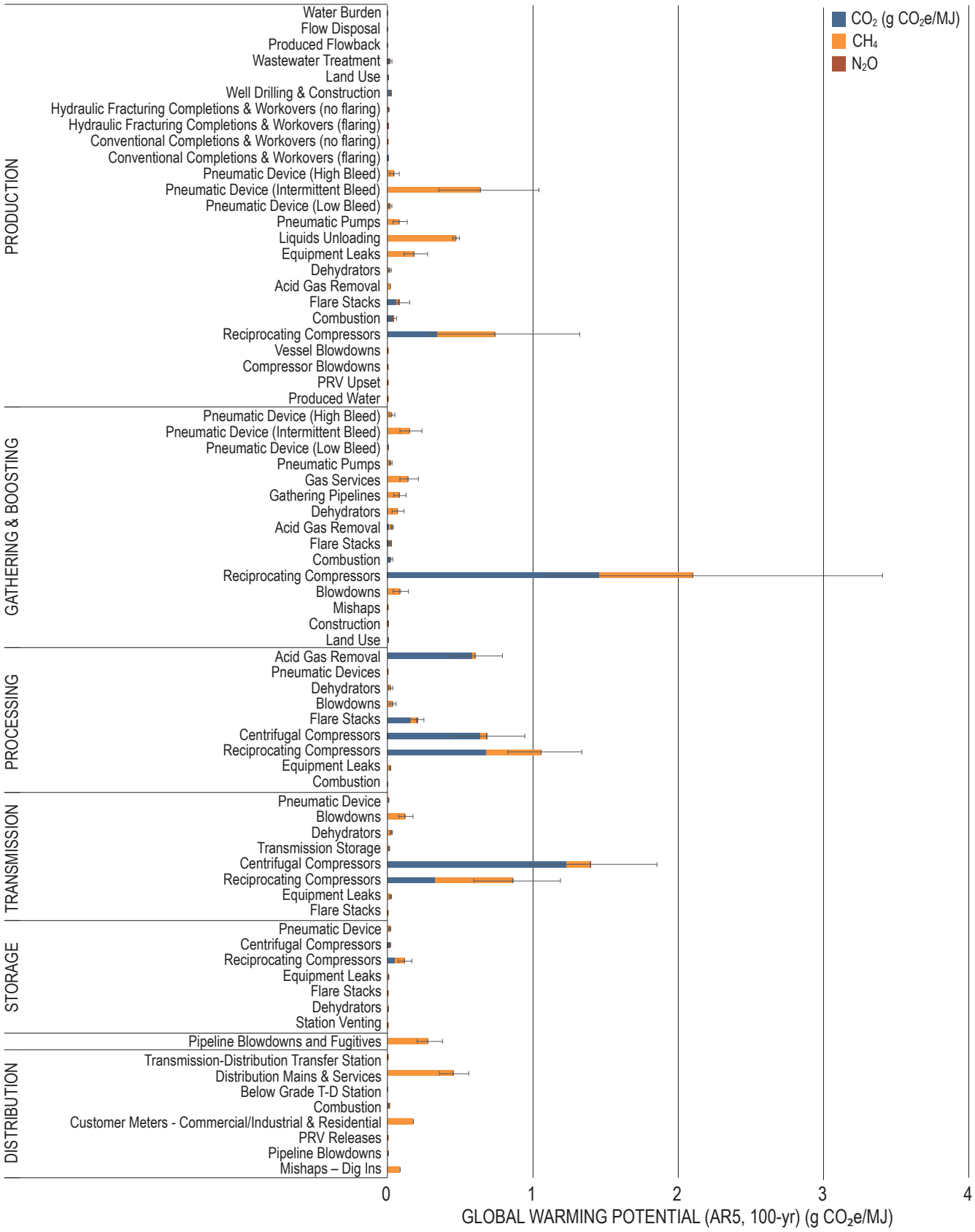
The GHG Protocol was first published in 2001 and was developed by the World Resources Institute and the World Business Council for Sustainable Development. The protocol "provides standards, guidance, tools, and training for businesses and governments to measure and manage climate-warming emissions."[22]

The GHG Protocol consists of standards and guidance like those used in financial accounting. These are intended to help companies leverage existing data to prepare a GHG-focused inventory using a standardized approach and principles. The inventory may be used by internal and external stakeholders to assess and compare different companies. The World Resources Institute publishes a *Corporate Standard* ("Guidance for companies and other organizations preparing a corporate-level GHG emissions inventory"), a *Product Standard*

20 The conventional Permian gas illustrated here represents the older production areas of the region, different from the unconventional production that has been growing recently in the same geography.

21 National Academies of Sciences, Engineering, and Medicine. 2022. "Greenhouse Gas Emissions Information for Decision Making: A Framework Going Forward." Washington, D.C. The National Academies Press. https://doi.org/10.17226/26641.

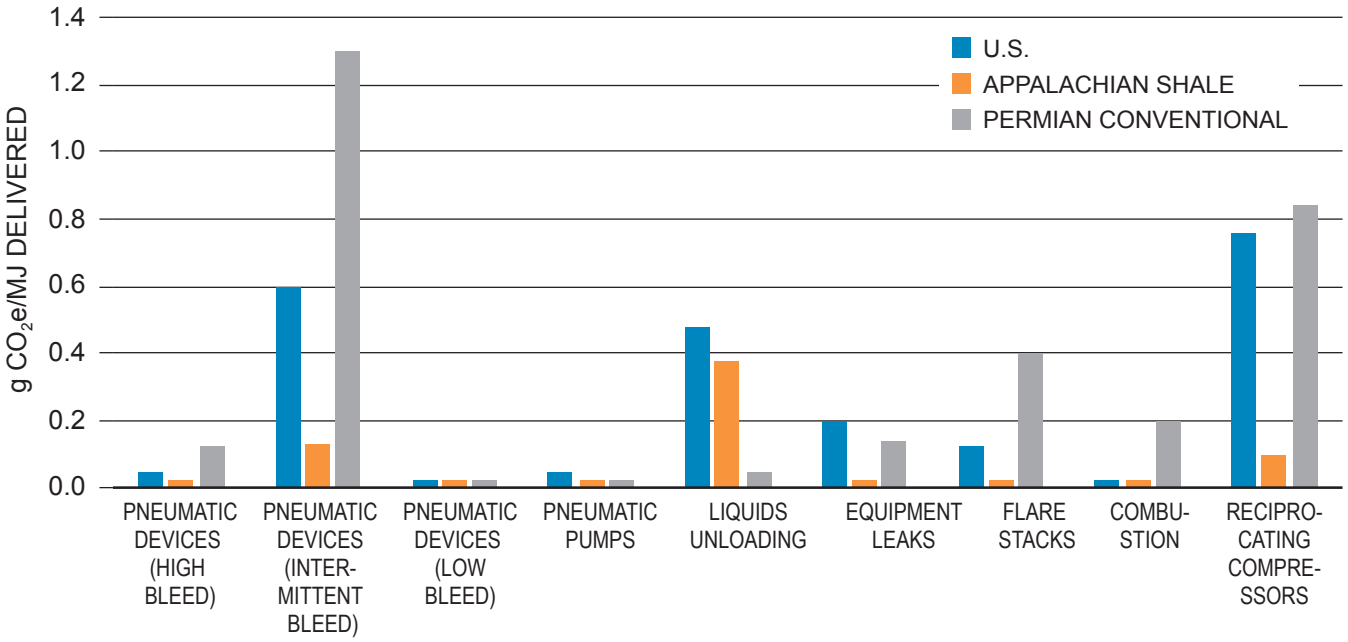
22 Greenhouse Gas Protocol. 2016. "About Us | Greenhouse Gas Protocol." https://ghgprotocol.org/about-us.



Note: Error bars represent the 95th percentile confidence intervals in mean values.

Source: NETL, Rai et al., 2021, https://doi.org/10.2172/1647225.

Figure 4-4. *Life Cycle GHG Emissions for U.S. Natural Gas in 2017, Estimated by NETL*



Note: 2017 production.

Source: NETL, Rai et al., 2021, https://doi.org/10.2172/1647225.

Figure 4-5. *Comparison of Select Production Emissions Sources Among U.S. Average, Appalachian Shale, and Permian Conventional Scenarios*

(guidance for estimating the footprint of a specific product), and a *Value Chain Standard.*

Of significance to many companies and corporations are GHG emissions scopes and subcategories introduced as part of the GHG Protocol standards. There are three scopes considered in the GHG Protocol:

- **Scope 1:** GHG emissions are those directly resulting from the combustion of fuels by assets owned or controlled by a reporting company. This includes emissions from fleet vehicles, natural gas combustion sources, and on-site electricity generation. Fugitive emissions of GHGs by the reporting company are also considered to be Scope 1.
- **Scope 2:** GHG emissions are those associated with generation of electricity, steam, heat, or cooling purchased and consumed by the reporting company.[23]
- **Scope 3:** GHG emissions are those resulting indirectly from the reporting entity's supply chain activities involving sources that a company does not own or control. Scope 3 emissions are divided into 15 upstream and downstream categories that include the reporting entity's supply chain emissions, employee commuting and business travel, use of sold products, including end use and end-of-life disposal.[24]

GHG Protocol does not yield emissions that are specific to any product (e.g., carbon intensity) made by an individual company that makes multiple products. That is, estimation of the Scope 1, 2, and 3 emissions associated with a company's many products may utilize the same emissions sources as an LCA, but these sources do not directly yield CFPs for each individual company product.

2. *ISO 14064*

In 2006, the ISO published *ISO 14064*,[25] a standard defining minimum requirements to establish

23 Greenhouse Gas Protocol. "Scope 2 Guidance | GHG Protocol." 2015. https://ghgprotocol.org/scope-2-guidance.

24 Greenhouse Gas Protocol. "Corporate Value Chain (Scope 3) Standard | GHG Protocol." September 2011. https://ghgprotocol.org/corporate-value-chain-scope-3-standard.

25 ISO 14064-1:2018. International Standard. Greenhouse Gases – Part 1: Specification with guidance at the organization level for quantification and reporting of greenhouse gas emissions and removals. International Organization for Standardization. December 2018. https://www.iso.org/standard/66453.html.

GHG emissions inventories. *ISO 14064* creates a framework that is intended to ensure consistency, auditability, and credibility across entities in both public and private sectors. The three-part standard addresses specifications for organization and project activity-level quantification, reporting, and independent verification of GHG emissions removals using a bottom-up data approach. *ISO 14064* largely aligns with, and builds upon, the GHG Protocol standards. However, like the GHG Protocol standards, it does not define the CFPs of products per se.

3. Oil and Gas Methane Partnership (OGMP) 2.0

As discussed in Chapter 1, the Oil & Gas Methane Partnership 2.0[26] (OGMP 2.0) is a multi-stakeholder initiative launched by the U.N. Environment Programme (UNEP) and the Climate and Clean Air Coalition. OGMP 2.0 is exclusively focused on reporting methane emissions in the oil and gas sector.

The key focus of the OGMP 2.0 program is to incorporate measurement data over time to develop measurement-informed inventories in relation to Scope 1 emissions across its primary operations and joint-ventures, while its focus on methane emissions from a firm's assets makes the results insufficient for characterizing GHG emissions throughout the product supply chain, nevertheless, asset-specific data gathered as part of OGMP 2.0 obligations might serve as key data inputs for unit process inventories in LCAs of natural gas.

4. EPA GHG Reporting Program (GHGRP)

The GHGRP[27] was established by the EPA in 2009. The program requires reporting of GHG data and other relevant information from large GHG emissions sources. Facilities are generally required to submit annual reports under 40 CFR Part 98[28] if they emit 25,000 metric tons CO_2e or more per year.

The EPA maintains a dataset of GHG emissions (including a subset of activity data, such as flowrates) for various specific industries and processes, and this data has been used in some LCAs of natural gas, including those published by the U.S. Department of Energy (DOE) NETL and private entities. However, it is important to note that it does not represent a comprehensive dataset of all U.S. operations, as not all facilities are required to report, and some may report aggregated information due to physical vicinity of facilities, even though the operations may fall in different phases of a natural gas life cycle. This may cause accidental ascription of certain types of emissions to phases of the natural gas life cycle where no such emissions occur, though this is likely the case with any emissions reporting program today. Also previously discussed, currently as implemented, the GHGRP relies on the use of engineering emissions factors that are based on empirical data[29] from prior published studies and does include the use of facility specific direct measurements for certain emissions sources.[30] The National Academies of Sciences, Engineering, and Medicine has analyzed activity-based inventories such as GHGRP and the GHGI and offered recommendations in improving these inventories.[31, 32] Under Section 136 of the Clean

26 OGMP 2.0 – the Oil & Gas Methane Partnership 2.0. n.d. https://www.ogmpartnership.com/.

27 EPA. 2014. "Greenhouse Gas Reporting Program (GHGRP)." June 10, 2014. https://www.epa.gov/ghgreporting.

28 EPA. "CFR Title 40, Chapter 1, Subchapter C, Part 98 – Mandatory Greenhouse Gas Reporting." October 30, 2009. Updated March 26, 2024. https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98.

29 Per 88 FR 50286 "EPA interprets empirical data to mean data that are collected by conducting observations and experiments that could be used to accurately calculate emissions at a facility, including direct emissions measurements, monitoring of CH_4 emissions (e.g., leak surveys) or measurement of associated parameters (e.g., flow rate, pressure, etc.), and published data."

30 EPA. "40 CFR 98: Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems." August 1, 2023. Federal Register. Vol. 88, Issue 146. https://www.govinfo.gov/content/pkg/FR-2023-08-01/pdf/2023-14338.pdf.

31 National Academies of Sciences, Engineering, and Medicine. "Improving Characterization of Anthropogenic Methane Emissions in the United States." 2018. Washington, D.C. National Academies Press. https://doi.org/10.17226/24987.

32 National Academies of Sciences, Engineering, and Medicine. 2022. "Greenhouse Gas Emissions Information for Decision Making: A Framework Going Forward." Washington, D.C. National Academies Press. https://doi.org/10.17226/26641.

Air Act,[33] Congress mandates the EPA to "revise requirements of Subpart W" under the GHGRP to ensure reporting of emissions under Subpart W incorporates empirical or measurement-informed datasets to "accurately reflect the total methane emissions" and "allow owners and operators of applicable facilities to submit empirical emissions data." EPA has proposed revisions[34] to Subpart W of the GHGRP to allow for use of empirical or measurement-informed datasets and methods.

5. Methane Leak Rate

As previously discussed, an intensity metric normalizes emissions because of some specified activity. Over the past 10 years, an alternative metric commonly referred to as methane leak rate has appeared in the dialogue regarding the environmental performance of natural gas systems. It focuses on the emissions of methane over the life cycle of a natural gas system, and is often calculated as mass of methane emitted divided by mass of natural gas produced or sold (as methane (CH_4)), i.e., kg CH_4 emitted/kg natural gas produced or sold (or as CH_4), and ostensibly includes emissions not only associated with leaks, but also venting and uncombusted methane associated with engine exhaust, flares, and other combustion sources. The methane leak rate is often reported on a percentage basis. The composition of natural gas is majority methane; thus, methane emissions have been used as a proxy for natural gas leakage.

For comprehensively understanding and comparing GHG emissions from natural gas products across the supply chain, life cycle GHG emissions inventories have several advantages over using methane leak rate. First, most methane emissions calculations and measurements often do not capture the full supply chain like LCAs do, and thus do not provide as complete a comparison of the product (i.e., natural gas) across the supply chain. Second, LCAs capture the impacts of all GHGs, including methane and carbon dioxide emissions. As found in this report, whereas methane is an important component of life cycle GHG emissions, it is not the sole contributor. Carbon dioxide makes a material contribution to total GHG emissions, considering both long and short time horizons,[35] and varies across supply chains for reasons different from methane emissions.

Third, natural gas life cycle GHG emissions results are reported normalized by the function unit (i.e., throughput of gas at the end of the supply chain boundary). This normalization by gas throughput is important because the metric inherently incorporates consideration of the efficiency of comparative supply chains in delivering the product (i.e., use and loss of natural gas along the supply chain). Further, the choice by the National Petroleum Council (NPC) study of a megajoule (MJ) of natural gas as the functional unit aligns with how natural gas is evaluated by customers, investors, and regulators. Life cycle GHG emissions normalized per MJ enables direct comparison by customers of natural gas products to other fuel choices and to understand the attribution of GHG emissions to derivative products, such as chemicals, products that use natural gas as an energy source, and by product-focused regulations such as carbon border adjustment mechanisms. This metric enables a purchaser, investor, or regulator to differentiate products fairly and rigorously with one metric.

Finally, LCAs require allocation of GHG emissions to products commonly produced along with natural gas (e.g., NGLs, oil, etc.),[36] which is not typically performed when measuring methane emissions. If emissions are not allocated to all coproducts, the implication is that those coproducts have no environmental burden in one or more of their life cycle phases (e.g., oil and gas production). Allocation of measured methane emissions to natural gas, NGL, and oil is challenging in the absence of geospatial and operational data. Although challenging in the absence of geospatial

33 EPA. 2022. "40 CFR 98: Methane Emissions and Waste Reduction Incentive Program and Revisions to the Mandatory Greenhouse Gas Reporting Rule for Petroleum and Natural Gas Systems." https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202210&RIN=2060-AV83.

34 EPA. "40 CFR 98: Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems." August 1, 2023. Federal Register. Vol. 88, Issue 146. https://www.govinfo.gov/app/details/FR-2023-08-01/2023-14338.

35 This study uses 100-year GWP values from the IPCC's Fifth Assessment Report unless otherwise stated (noted as 'GWP100,' where the GWP of methane is 28). Results for 20-year GWP values (where GWP of methane is 82) are shown in this chapter and Appendix E. Megajoules (MJ) are reported on a higher heating value (HHV) basis.

36 Also known as coproduct allocation.

and operational data, properly allocated GHG emissions are necessary to provide a representative GHG emissions intensity of natural gas and coproducts across the natural gas supply chain.

6. Consequential LCAs

GHG LCAs can support decision-makers by providing representative estimates of GHG emissions intensities from the product or process across the supply chain to help estimate the net GHG emissions that could result from introduction of the product or process to the market.[37] In the overwhelming majority of LCAs, environmental impacts for a supply chain are *attributed* to the product. For this reason, LCAs as discussed thus far are sometimes called attributional LCAs. An LCA that estimates the cradle-to-grave emissions associated with 1 MWh of electricity generated by a specific natural gas-fired power plant is one example. Such LCAs do not consider how individual supply chains may impact other supply chains or the larger market. Most previously done LCAs of energy, chemicals, and commodity products are, thus, attributional.

By contrast, investigations of the environmental impact associated with the introduction of a product or service into the marketplace are commonly referred to as *consequential LCAs*. Beyond the attributional aspects above, such studies may also consider market-based effects, such as how higher- or lower-priced goods and services affect the product system of interest as well as others. At the very least, counterfactual scenarios are required addressing what would have happened in the absence of the introduction of a particular good or service, thus introducing a subjective choice. Consequential LCAs often employ complex macroeconomic models to define a set of energy market or policy scenarios and to estimate the related effects.

When emissions are to be assigned to products or services to determine the direct emissions from producing and consuming the product or providing the service to society without considering how the choice to use the product or process effects other markets and consumer decisions, an attributional LCA is appropriate. This is the case in the present study, as NPC seeks to determine the carbon intensity of natural gas from multiple basins along multiple supply chains to identify opportunities for environmental improvement.

Overall, attributional and consequential LCAs are not directly comparable, even though the results of both LCAs may be reported using the same units. An attributional LCA estimates environmental burdens of a product whereas a consequential LCA estimates net environmental impacts associated with bringing that product into the marketplace, accounting for how the marketplace would respond in terms of overall supply mix. Additional findings and recommendations on consequential LCAs are discussed in Section VII, Summary of Findings & Recommendations, of this chapter.

II. BACKGROUND ON LCAs OF NATURAL GAS

Many LCAs of natural gas produced in the United States have been published since the publication of *ISO 14040* in 1997. The first of which the study is aware was published by the DOE National Renewable Energy Laboratory (NREL) in 2000.[38] Seven years later, Jaramillo and coworkers published the first peer-reviewed LCA of U.S. natural gas.[39] Other influential LCAs from this period included those of DOE NETL in 2010[40] and the investigation of uncertainty in LCAs of natural gas by Venkatesh et al.[41]

37 National Academies of Sciences, Engineering, and Medicine. 2022. "Current Methods for Life Cycle Analyses of Low-Carbon Transportation Fuels in the United States." Washington, D.C. National Academies Press. https://doi.org/10.17226/26402.

38 Spath, Pamela and Margaret Mann. 2000. "Life Cycle Assessment of a Natural Gas Combined-Cycle Power Generation System." National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy00osti/27715.pdf.

39 Jaramillo, P., Griffin, W.M., and Matthews, H.S. 2007. "Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation." *Environmental Science & Technology* 41 (17): 6290–96. https://doi.org/10.1021/es063031o.

40 National Energy Technology Laboratory (NETL). "Life Cycle Analysis: Natural Gas Combined Cycle Power Plant (NGCC)." National Energy Technology Laboratories. August 23, 2010.

41 Venkatesh, A., Jaramillo, P., Griffin, W.M., and Matthews, H.S. 2011. "Uncertainty in Life Cycle Greenhouse Gas Emissions from United States Natural Gas End-Uses and Its Effects on Policy." *Environmental Science & Technology* 45 (19): 8182–89. https://doi.org/10.1021/es200930h.

Beginning in 2011, an increasing number of LCAs of shale gas were published in the peer-reviewed literature, responding to nonpeer-reviewed claims regarding the GHG intensity of shale gas. Initial investigations by Jiang et al.,[42] Hultman et al.,[43] Stephenson et al.,[44] and Burnham et al.,[45] were influential, but they had limited data from operations. Laurenzi and Jersey were the first to introduce industrial data into an LCA of shale gas.[46]

By 2012, it was evident that there was notable variability in the results of LCAs of U.S. shale gas. Weber and Clavin[47] were the first to attempt a harmonization of the studies published in 2011 to improve consistency of results via reconciliation of their system boundaries and assumptions. In 2014, Heath et al., at NREL published a comprehensive harmonization study of all LCAs of shale gas in the *Proceedings of the National Academy of Sciences.*[48]

By 2015, there was considerable interest in the potential GHG emissions associated with U.S. LNG, even though LNG would not be exported from the United States until February of 2016. The first peer-reviewed paper on the topic of U.S. LNG was published by Abrahams et al., in 2015,[49] focusing on potential impacts of methane emissions, although lacking a process model or industrial data for the GHG emissions associated with liquefaction in the U.S. context. In 2018, Mallapragada et al., published an LCA of LNG sourced from Marcellus shale gas,[50] using process modeling to estimate the GHG emissions associated with liquefaction, and adopting results of the aforementioned methane emissions measurement studies to more robustly estimate methane emissions upstream of the LNG plant. In 2021, Roman-White et al., published the first LCA of U.S. LNG using data from an operating LNG plant.[51] More recently, the first global studies, including Tanaka et al., (2019),[52] and Jordaan et al., (2022),[53] examined cases across multiple countries that included U.S. supply chains, including LNG shipping.

Many academic studies over the past decade have focused on the experimental quantification of methane emissions in the natural gas supply chain, including many studies conducted as collaborations between the Environmental Defense Fund, oil and gas companies, academic researchers, and U.S. National Laboratories. The findings

42 Jiang, M., Griffin, W.M., Hendrickson, C., Jaramillo, P., VanBriesen, J., and Venkatesh, A. 2011. "Life Cycle Greenhouse Gas Emissions of Marcellus Shale Gas." *Environmental Research Letters* 6 (3): 034014. https://doi.org/10.1088/1748-9326/6/3/034014.

43 Hultman, N., Rebois, D., Scholten, M., and Ramig, C. 2011. "The Greenhouse Impact of Unconventional Gas for Electricity Generation." *Environmental Research Letters* 6 (4): 044008. https://doi.org/10.1088/1748-9326/6/4/044008.

44 Stephenson, T., Valle, J.E., and Riera-Palou, X. 2011. "Modeling the Relative GHG Emissions of Conventional and Shale Gas Production." *Environmental Science & Technology* 45 (24): 10757–64. https://doi.org/10.1021/es2024115.

45 Burnham, A., Han, J., Clark, C.E., Wang, M., Dunn, J.B., and Palou-Rivera, I. 2011. "Life-Cycle Greenhouse Gas Emissions of Shale Gas, Natural Gas, Coal, and Petroleum." *Environmental Science & Technology* 46 (2): 619–27. https://doi.org/10.1021/es201942m.

46 Laurenzi, Ian J., and Gilbert R. Jersey. 2013. "Life Cycle Greenhouse Gas Emissions and Freshwater Consumption of Marcellus Shale Gas." *Environmental Science & Technology* 47 (9): 4896–4903. https://doi.org/10.1021/es305162w.

47 Weber, Christopher L., and Christopher Clavin. 2012. "Life Cycle Carbon Footprint of Shale Gas: Review of Evidence and Implications." *Environmental Science & Technology* 46 (11): 5688–95. https://doi.org/10.1021/es300375n.

48 Heath, G.A., O'Donoughue, P., Arent, D.J., and Bazilian, M. 2014. "Harmonization of Initial Estimates of Shale Gas Life Cycle Greenhouse Gas Emissions for Electric Power Generation." *Proceedings of the National Academy of Sciences* 111 (31): E3167–76. https://doi.org/10.1073/pnas.1309334111.

49 Abrahams, L.S., Samaras, C., Griffin, W.M., and Matthews, H.S. 2015. "Life Cycle Greenhouse Gas Emissions from U.S. Liquefied Natural Gas Exports: Implications for End Uses." *Environmental Science & Technology* 49 (5): 3237–45. https://doi.org/10.1021/es505617p.

50 Mallapragada, D.S., Reyes-Bastida, E., Roberto, F., McElroy, E.M., Veskovic, D., and Laurenzi, I.J. 2018. "Life Cycle Greenhouse Gas Emissions and Freshwater Consumption of Liquefied Marcellus Shale Gas Used for International Power Generation." *Journal of Cleaner Production* 205 (December): 672–80. https://doi.org/10.1016/j.jclepro.2018.09.111.

51 Roman-White, S.A., Littlefield, J.A., Fleury, K.G., Allen, D.T., Balcombe, P., Konschnik, K.E., Ewing, J., Ross, G.B., and George, F. 2021. "LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting." *ACS Sustainable Chemistry & Engineering* 9 (32): 10857–67. https://doi.org/10.1021/acssuschemeng.1c03307.

52 Tanaka, K., Cavalett, O., Collins, W.J., and Cherubini, F. 2019. "Asserting the Climate Benefits of the Coal-To-Gas Shift across Temporal and Spatial Scales." *Nature Climate Change* 9 (5): 389–96. https://doi.org/10.1038/s41558-019-0457-1.

53 Jordaan, S.M., Ruttinger, A.W., Surana, K., Nock, D., Miller, S.M., and Ravikumar, A.P., 2022. "Global Mitigation Opportunities for the Life Cycle of Natural Gas-Fired Power." *Nature Climate Change*, 12(11), pp.1059-1067. https://doi.org/10.1038/s41558-022-01503-5.

from some of these studies have been incorporated into many LCAs in subsequent years to a certain extent. Tavakkoli et al.,[54] compared EPA inventories against published measurement studies for methane emissions rates from the natural gas supply chain.[55, 56] Other studies have conducted measurements and employed the data in their LCAs, such as Contreras et al.[57] However, there has been limited incorporation of empirical emissions data as inputs to LCA unit processes or product systems across each stage of the natural gas supply chain. Roman-White et al.,[58] conducted a sensitivity analysis of a customized supply chain of a major LNG exporter using supplier-specific data and empirical data from measurement studies by Lyon et al.,[59] and Rutherford et al.,[60] for flaring and fugitive emissions sources and found that net GHG emissions intensity can vary relative to a baseline LCA case using conventional engineering estimated emissions factors. As discussed in detail in Chapter 3, reliable quantification of measurement-informed inventories remains a challenge that is not unique to its use in LCAs. Developing such tools is an important enabler of certain types of policy designs that are under consideration by policymakers in the United States. The aforementioned studies are by no means a comprehensive survey of LCAs of U.S. natural gas. The NPC study will address more recent external studies in the context of the harmonization study later in this chapter.

III. NATURAL GAS SUPPLY CHAIN STAGE DESCRIPTIONS IN THE CONTEXT OF LCA

The operations in any particular natural gas supply chain will depend upon the composition of the gas and the pressure of the reservoir from which it is sourced, among other factors. Furthermore, each company producing, gathering, or processing gas in a particular geographical region may operate its assets differently from its competitors, even if the gas is produced from the same reservoir at similar pressures and compositions. Moreover, a single company may operate assets differently in association with the same oil or gas reservoir for a variety of reasons. Due to these multiple drivers, there will be variability in GHG emissions intensities assessed via LCAs using operator-specific data.

The following sections provide additional detail on the processes and emissions related to each stage of the natural gas and LNG supply chain.

A. Production

1. Drilling and Completion

The life cycle of natural gas begins with drilling and completion of a well, which includes the following operations:

- Insertion of steel pipe (tubulars) and injection of cement to ensure integrity of the well, separate geological formations from each other, and protect groundwater closer to the surface
- Hydraulic fracturing (in case of unconventional wells), which allows oil and gas to be produced from hydrocarbon-bearing rock with low permeability and porosity. During this process, the

54 Tavakkoli, S., Feng, L., Miller, S.M., and Jordaan, S.M. 2022. "Implications of Generation Efficiencies and Supply Chain Leaks for the Life Cycle Greenhouse Gas Emissions of Natural Gas-Fired Electricity in the United States." *Environmental Science & Technology* 56 (4): 2540–50. https://doi.org/10.1021/acs.est.1c05246.

55 Brandt, A.R., Heath, G.A., Kort, E.A., O'Sullivan, F., Petron, G., Jordaan, S.M., Tans, P., et al. 2014. "Methane Leaks from North American Natural Gas Systems." *Science* 343 (6172): 733–35. https://doi.org/10.1126/science.1247045.

56 Alvarez, R.A., Zavala-Araiza, D., Lyon, D.R., Allen, D.T., Barkley, Z.R., Brandt, A.R., Davis, K.J., et al. 2018. "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain." *Science* 361 (6398): eaar7204. https://doi.org/10.1126/science.aar7204.4.

57 Contreras, W., Hardy, C., Tovar, K., Piwetz, A.M., Harris, C.R., Tullos, E.E., Bymaster, A., McMichael, J., and Laurenzi, I.J. 2021. "Life Cycle Greenhouse Gas Emissions of Crude Oil and Natural Gas from the Delaware Basin." *Journal of Cleaner Production*, October, 129530. https://doi.org/10.1016/j.jclepro.2021.129530.

58 Roman-White, S.A., Littlefield, J.A., Fleury, K.G., Allen, D.T., Balcombe, P., Konschnik, K.E., Ewing, J., Ross, G.B., and George, F. 2021. "LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting." *ACS Sustainable Chemistry & Engineering* 9 (32): 10857–67. https://doi.org/10.1021/acssuschemeng.1c03307.

59 Lyon, D.R., Hmiel, B., Gautam, R., Omara, M., Roberts, K.A., Barkley, Z.R., Davis, K.J., et al. 2021. "Concurrent Variation in Oil and Gas Methane Emissions and Oil Price during the COVID-19 Pandemic." *Atmospheric Chemistry and Physics* 21 (9): 6605–26. https://doi.org/10.5194/acp-21-6605-2021.

60 Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P., Heath, G.A., Englander, J., Cooley, D., Lyon, D., et al. 2021. "Closing the Methane Gap in U.S. Oil and Natural Gas Production Emissions Inventories." *Nature Communications* 12 (1). https://doi.org/10.1038/s41467-021-25017-4.

formation containing oil and gas is perforated or fractured. Next, water or gel is injected into the well at high pressure to open the resulting fractures. Proppant, often sand or ceramic particles, is injected along with the water to hold the fractures open after the high-pressure water is allowed to return to the surface via the well. With the fractures propped open, gas and oil may be produced from the rock.

- Flowback, where much of the injected water along with gas and potentially other heavier hydrocarbons return to the surface via the well. Historically, much of the gas produced during flowback was flared in many of the U.S. shale gas basins. Today, much of this gas is recovered and goes to the gas gathering system (green completions). Produced water is collected and sent to Class II saltwater disposal (SWD) wells.

Power for drilling operations is often sourced from diesel engines or diesel-generator sets but is increasingly driven by grid electricity. In recent years, technology has become available for electrically driven hydraulic fracturing, sourced from grid electricity or on-site natural gas power generation.

The GHG emissions associated with drilling and completion operations will depend on the specific types of equipment employed. The construction of a well pad will have vehicle emissions associated with the delivery of materials. Emissions associated with drilling and completion may be due to the combustion of diesel, or use of electricity with a nonzero CFP; fugitive emissions may also be possible, e.g., due to incomplete water-gas separation during flowback. Direct emissions associated with completion flaring or venting may also occur.

2. Gas Production to Sales

As flowback comes to an end, the gas or oil well enters the production phase. Hydrocarbons and water from the subsurface (produced water) enter one or more separators, which separate gas, produced water, and crude oil (for oil wells). Liquid levels in separators are often controlled via (natural gas) pneumatic devices. Gas goes to a gathering pipeline, whereas water (and oil) is often produced to tanks in the vicinity of the separator(s), and then transported via truck or pipeline. Produced water is transported to SWD facilities, where it is injected into Class II wastewater disposal wells. In some cases, produced water is treated and recycled for other uses. Flares may also be located at sites where water, gas, and oil are separated. Operations typical of this phase of the natural gas life cycle are depicted in Figure 4-6.

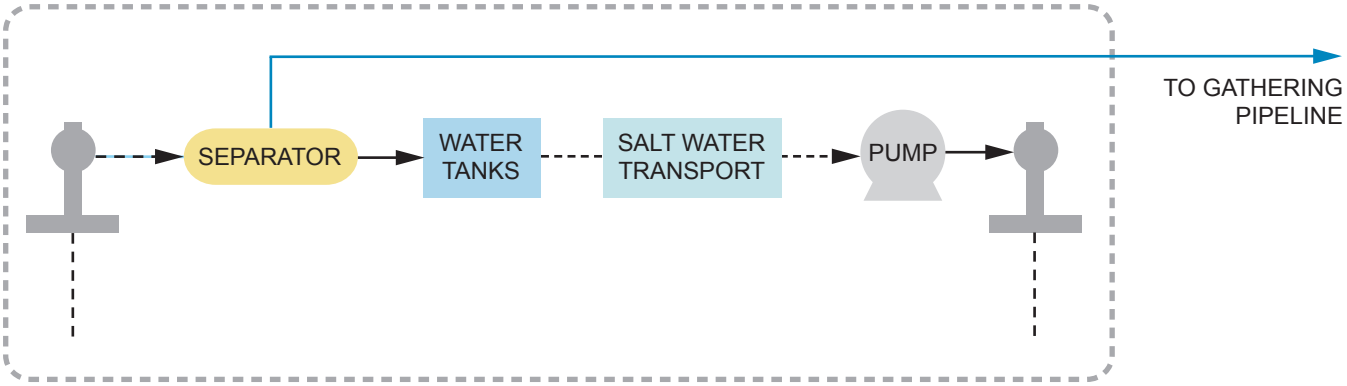
Oil-producing well pads may also feature oil-specific equipment such as pumping units, electric submersible pumps, or natural gas compressors (used for gas lift). Some of this equipment may be present for certain phases of the well life cycle but not others.

Wellhead equipment associated with production is predominantly driven by electricity, although small natural gas engines are employed by some operators to drive pumping units in remote locations, with the natural gas sourced from the well. Increasingly, industry is replacing (natural gas) pneumatic devices with instrument air and other technologies to reduce methane emissions. Instrument air systems are powered by electricity.

For some oil and gas wells, a process known as liquids unloading is periodically employed to remove produced water from the well bore and thereby restore the flow of gas (and potentially oil). One of these processes drives water flow by decreasing the pressure at the wellhead via venting the well to atmosphere.

GHG emissions associated with production may result from combustive and noncombustive sources. Noncombustive sources may include (natural gas) pneumatic devices, chemical injection pumps, certain liquids unloading procedures, and to a lesser degree, leaks associated with flanges, etc., yielding methane emissions.

Dehydrators, while uncommon at gas production sites, may also be a source of fugitive methane emissions. Combustion emissions at production sites may be associated with heater treaters (for oil wells), inline heaters, and in some specific cases, gas engines used to drive pumping units (at oil wells). Lastly, there are indirect emissions associated with purchased power (Scope 2 emissions) and the emissions upstream of power generators (Scope 3 emissions, Categories 1-8).



Notes: Other equipment may be present for oil wells that produce natural gas. More than one well may feed a separator, and produced water from many separators may be injected at a common facility.

Figure 4-6. *Illustrated Example of Equipment Associated with the Production Phase of a Natural Gas Life Cycle (Nonassociated Gas)*

B. Gathering and Boosting (G&B)

Production facilities are connected to the rest of the natural gas supply chain via a gathering system, which typically (but not always) features a compressor station to move the gas from the production facilities to a gas treatment or processing plant, or in some circumstances, a natural gas transmission pipeline; the circumstances will depend on whether the composition of the gathered gas meets the specifications of the transmission pipeline.

A compressor station typically used in shale gas and many associated gas gathering systems features one or more multistage compressors as illustrated in Figure 4-7. The amount of compressor power required to move the gas is proportional to the gas flow rate and is dependent upon the suction and discharge pressures. Individual multistage compressors are powered by electricity or high horsepower natural gas engines. If the prime mover of the compressor station is a gas engine, then it may be fueled by a portion of the raw gas at the compressor station. If the gas at the compressor station inlet is saturated with water vapor, then a dehydration unit may also be present. Furthermore, water or hydrocarbons that condense during compression may be stored in tanks at the site.

GHG emissions at the compressor station arise from combustion of natural gas or other fuels (gas engine or dehydrator fuel), and fugitive emissions, vents, and blowdowns. A portion of the emissions may arise from methane slip (i.e., uncombusted methane in the gas engine exhaust). Other emissions may be associated with piston rods[61] and pneumatic devices, among other smaller emissions sources. If compressors are driven by electricity, or if instrument air is used in lieu of natural gas pneumatic devices, then there will be indirect emissions associated with purchased power.

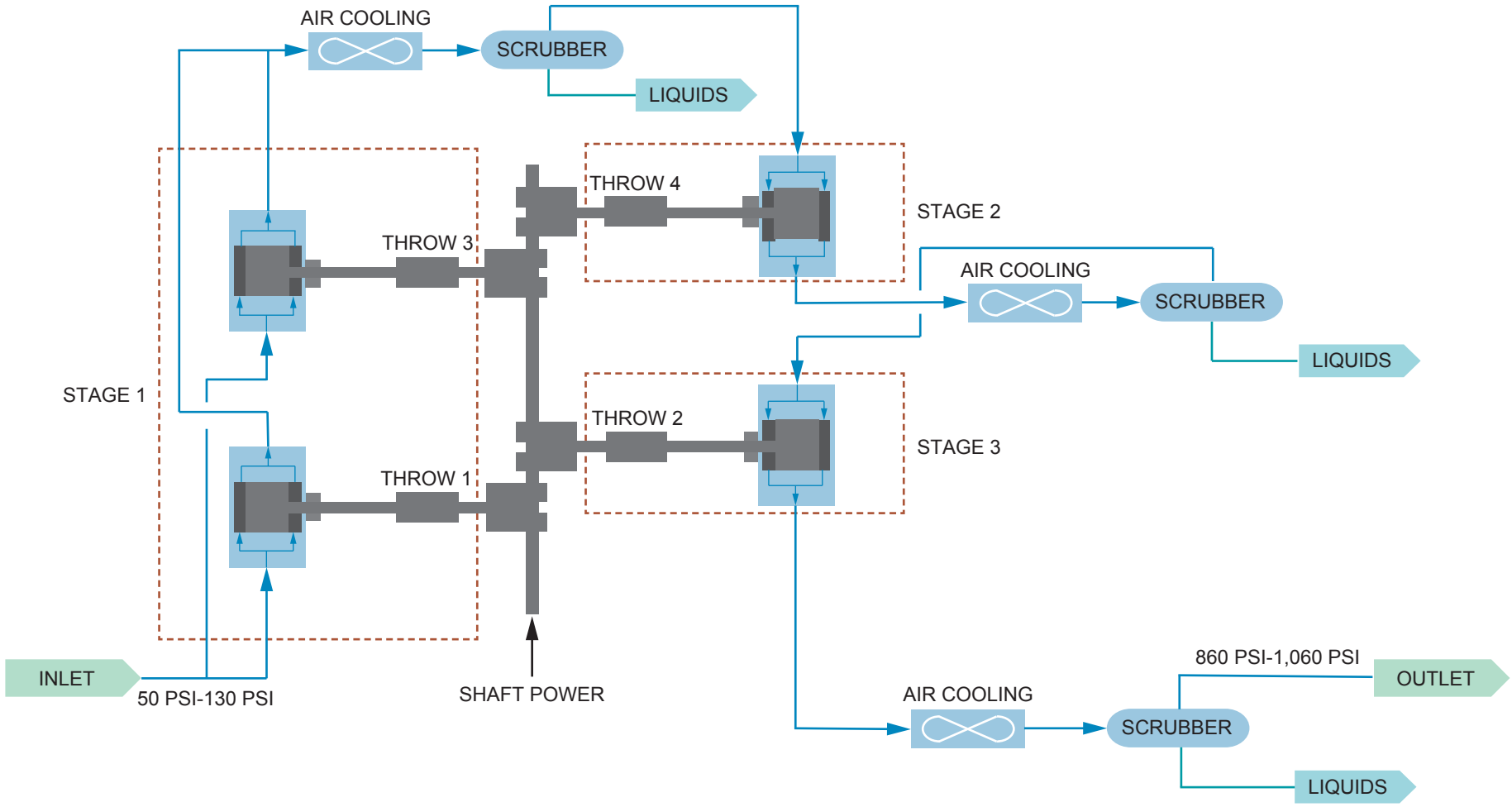
C. Treatment and Processing

Gas may be transferred directly from the compressor station to a transmission pipeline if the composition of the gas meets the specifications of that pipeline. More typically, the natural gas composition must be treated or processed to:

- Remove inert molecules such as CO_2 or nitrogen (N_2)
- Remove potentially corrosive molecules such as hydrogen sulfide (H_2S)
- Recover high-value NGLs such as ethane, propane, butanes, and pentanes

Molecules such as CO_2 or N_2 decrease the higher heating value of the gas, which is not desirable. Excessive amounts of NGL in natural gas may

61 EPA. "Reducing Methane Emissions from Compressor Rod Packing Systems." October 2006. https://19january2017snapshot.epa.gov/sites/production/files/2016-06/documents/ll_rodpack.pdf.



Note: A natural gas engine or electric motor (prime mover) rotates a shaft that drives multiple piston cylinders.

Source: Pressure ranges reported here are 25th to 75th percentiles reported by Mitchell et al., 2015, https://doi.org/10.1021/es5052809.

Figure 4-7. *Illustrative Example of One of Many Possible Multistage Compressor Configurations in a Natural Gas Gathering System*

cause hydrocarbon liquid dropout in transmission lines, which may be problematic.

Gas treatment typically refers to removal of water, CO_2, and H_2S from the natural gas. By contrast, gas processing typically refers to removal of NGLs or, much less commonly, N_2. The processes featured at a gas treatment or processing plant will depend on the composition of the gas:

- **Acid Gas Removal (AGR)** typically employs an aqueous amine to remove CO_2 and/or H_2S from natural gas. The amine is subsequently recovered by heating, concurrently producing acid gas components that may be routed to a thermal oxidizer in most cases, subject to the composition. The gas leaving an AGR unit will often be saturated with water, thereby requiring dehydration before being transferred into a transmission pipeline. Power is required for pumps used to circulate aqueous amine between the units.
- **Dehydration processes** are found at most gas treatment and processing plants. There are alternative technologies employed depending on the type of gas processing at the facility (e.g., whether the gas will be cryogenically processed), and these processes have different power requirements.
- **Cryogenic separation processes** are often employed to recover NGLs (or, less frequently, remove N_2) from the gas. To avoid the formation of hydrates or other solids and meet the specifications of NGL, if water and CO_2 are present at the gas plant inlet, most must be removed. NGL recovery typically takes place at pressures lower than that of the transmission pipeline. Therefore, booster compression will be employed downstream of a cryogenic NGL separation process, often using compressors of the type employed for gathering systems.

Due to the heterogeneity of gas compositions by geological basin and associated treatment and processing requirements, GHG emissions at gas treatment and processing plants vary considerably across the United States. If cryogenic separation is employed, then booster compressors may yield the same types of emissions as compressor stations, although differ in magnitude. If gas is treated to remove CO_2, then the CO_2 will often be vented, although some operators will inject it into the subsurface for permanent sequestration or sell it to other companies for use in enhanced oil recovery, among other uses. Processes employing electricity will have indirect emissions associated with purchased power (Scope 2 emissions) and the emissions upstream of power generators (Scope 3 emissions, Categories 1–8). Fugitive emissions of methane and intermittent flaring due to process upsets may also occur in association with some of these procedures.

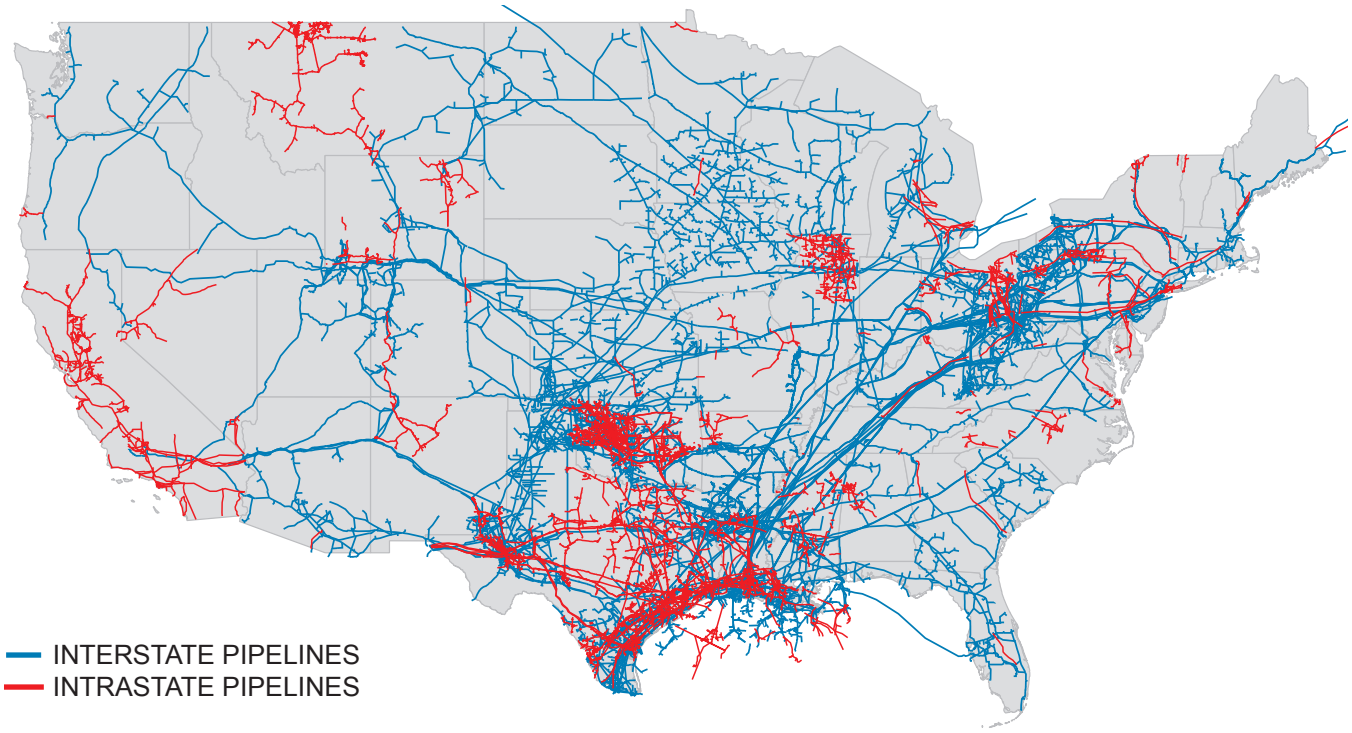
D. Transmission and Underground Storage

Following treatment or processing, natural gas flows to transmission pipelines (Figure 4-8). The system of large diameter, high-pressure pipelines include compressor stations and potentially storage facilities that deliver gas to industrial consumers (e.g., refineries, chemical plants, liquefaction facilities) and power plants. Transmission pipelines also transfer gas to low-pressure distribution pipelines at city gate stations, supplying gas to residential and commercial customers. Transmission pipelines typically operate at pressures between 500 psig and 1,400 psig.[62] Depending on the pressure of the gas delivered to the transmission pipeline and the distance to customers, among other factors, transmission pipelines may feature compressor stations to restore pressure lost due to friction and ensure gas flow. According to Argonne National Labs, these are situated at 40-mile to 100-mile intervals along the pipeline.[63] Certain transmission pipelines are connected to natural gas storage facilities, which may be depleted oil and gas wells, underground salt domes, or other geological formations, as well as peak shaving natural gas liquefaction plants.

The overwhelming majority of the energy usage associated with gas transmission and storage is sourced from a portion of the natural gas flowing through the system, which is used as fuel for gas turbines and gas engines that drive the compressor stations. Approximately 7% of

62 Folga, S.M. 2007. "Natural Gas Pipeline Technology Overview." Argonne National Laboratory. https://corridoreis.anl.gov/documents/docs/technical/apt_61034_evs_tm_08_5.pdf.

63 Folga, S.M. 2007. "Natural Gas Pipeline Technology Overview." Argonne National Laboratory. https://corridoreis.anl.gov/documents/docs/technical/apt_61034_evs_tm_08_5.pdf.



Source: EIA, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System.

Figure 4-8. *U.S. Natural Gas Pipeline Network in 2009*

energy usage by natural gas pipelines is sourced from electricity.

GHG emissions associated with natural gas transmission and storage include direct and indirect (Scope 2) emissions of CO_2 from compressor prime movers, methane slip from natural gas combustion, as well as fugitive emissions of methane. Zimmerle et al.,[64] reported that approximately 50% of the fugitive emissions are from major compressor equipment, including seal vents, unit isolation and blowdown valves, and rod packing, followed by "super-emitters," which contribute 24% to 48% of transmission fugitives and 10% to 54% of storage station fugitives.

E. Distribution

Natural gas distribution networks include pipelines and metering and regulating (pressure control) equipment at metering-regulating stations that are operated by local distribution companies. Distribution pipelines receive gas from transmission lines at city gate stations, where pressure is let down to 0.25 psig–300 psig.[65] The gas is delivered to largely residential and commercial end users. Natural gas power plants, refineries, and other large-scale industrial facilities (e.g., LNG plants) generally receive gas from transmission pipelines directly, but there are exceptions. Distribution facilities include transfer stations, metering-regulating stations, distribution mains and services, consumer meters, and pressure regulating valves, etc.

Methane emissions associated with gas distribution are attributed to the following sources: pipeline mains and services, M&R facilities, customer meters, maintenance, and upsets.

F. Liquefaction

Liquefaction of natural gas is employed to reduce its volume by more than 600 times, facilitating

64 Brandt, A.R., Williams, L., Vaughn, T.L., Quinn, C., Subramanian, R., Duggan, G.P., Willson, B., et al. 2015. "Methane Emissions from the Natural Gas Transmission and Storage System in the United States." *Environmental Science & Technology* 49 (15): 9374–83. https://doi.org/10.1021/acs.est.5b01669.

65 Folga, S.M. 2007. "Natural Gas Pipeline Technology Overview." Argonne National Laboratory. https://corridoreis.anl.gov/documents/docs/technical/apt_61034_evs_tm_08_5.pdf.

transport to customers over oceanic routes. LNG plants in the United States typically receive gas from transmission pipelines. At the LNG plant, molecules such as CO_2, H_2S, and mercury, as well as trace amounts of water and heavier hydrocarbons, are removed from the gas. The LNG-quality gas is then liquefied via cryogenic processes using specialized refrigeration processes. These refrigeration cycles are driven by compressors, which are powered by gas turbines or electricity.

GHG emissions associated with LNG plants may be direct (gas turbine exhaust, CO_2 removed from the gas) or indirect (emissions associated with purchased power). Fugitive emissions are also possible at the plant and associated operations that load LNG to ships.

G. Ocean Transport (LNG Shipping)

Following liquefaction, LNG is transported by ship to a variety of countries around the world. According to figures published by the U.S. Energy Information Administration (EIA), these destinations have changed dramatically in 2022 due to natural gas supply shifts resulting from supplying the war in Ukraine (Figure 4-9).[66]

The roundtrip transportation distances from the U.S. Gulf Coast and East Coast, where U.S. export facilities are predominantly sited, range from 6,500 to 20,000 nautical miles—the lower distances are typical of transport to Europe, whereas the higher distances are typical of transport to Asian & Pacific nations. The average vessel capacity globally is around 170,000 cubic meters and more than 65% of active LNG carriers have a capacity larger than 150,000 cubic meters.[67]

LNG carriers typically feature two engine types: one for propulsion, and one for auxiliary power. Historically, these were fueled by conventional marine fuels, but in recent years some LNG carriers have been employing a portion of the LNG cargo as fuel. Over the course of the voyage, a fraction of the LNG will vaporize due to heat incursions into cryogenic storage (boil-off gas or BOG). More than 90% of LNG carriers in the global fleet today burn BOG in their engines for propulsion[68] but also have gas combustion units and/or reliquefication equipment onboard such that any excess BOG would be combusted or reliquefied (i.e., not vented as methane). Only in extremely rare circumstances would a vessel vent methane for safety reasons. The choice to reliquefy is driven by economic considerations, which may be sensitive to the price of LNG relative to other marine fuels. According to International Gas Union, older vessels have BOG rates at 0.15% per day, but the newer membrane vessels have BOG rates closer to 0.07 % per day–0.085 % per day, with some vessels having ballast BOG rates as low as 0.04% per day.[69]

Most of the emissions associated with marine transportation/shipping of LNG are associated with combustion at the aforementioned engines. This predominantly yields CO_2. However, some engines utilizing natural gas as a fuel exhibit methane slip (i.e., emissions of uncombusted methane in the exhaust). The methane slip varies depending on the engine type; Dual Fuel Diesel Electric engines operating at lower pressures reportedly have higher methane slip than diesel cycle engines (such as the MEGI), which operate at higher pressures.[70]

Theoretically, there may also be methane emissions due to leaks or vents. However, in 2022, a peer-reviewed study by Balcombe et al., reported that venting and fugitive emissions associated with marine transport of LNG were extremely low, contributing less than 0.1% of total GHG emissions from the ship.[71]

66 EIA. "The United States Became the World's Largest LNG Exporter in the First Half of 2022." July 25, 2022. https://www.eia.gov/todayinenergy/detail.php?id=53159.

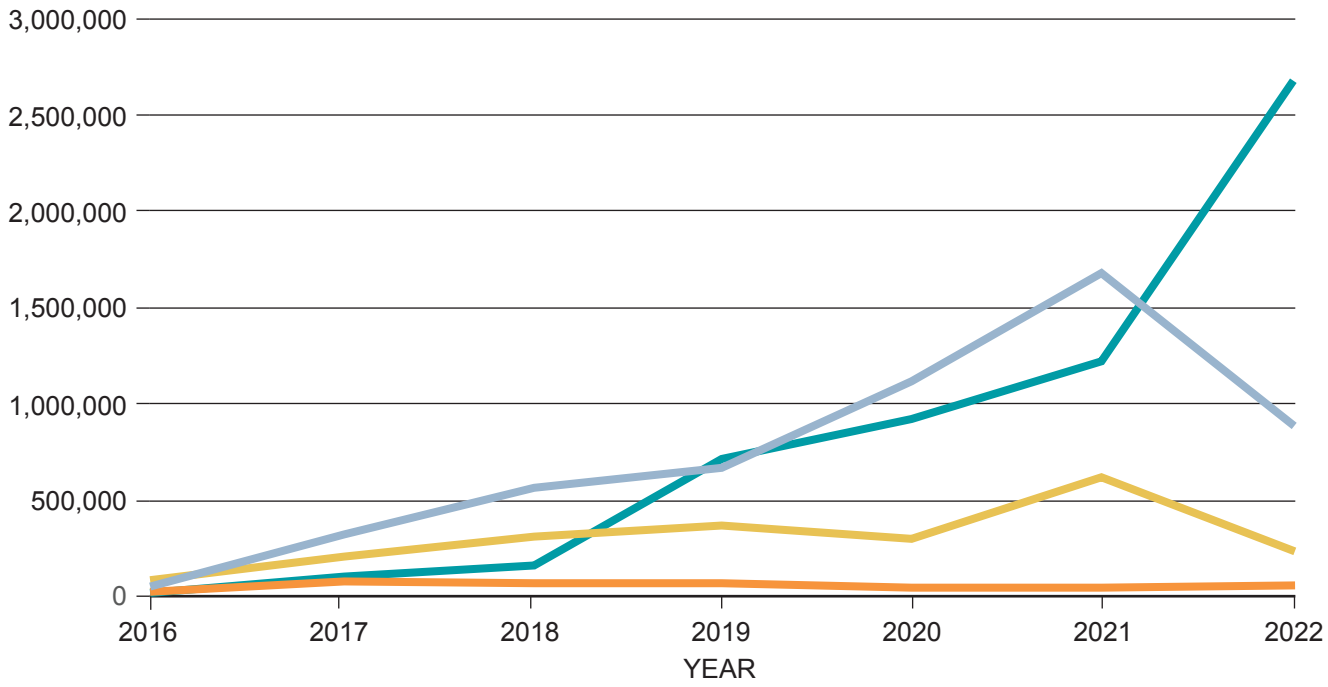
67 IGU. "2023 World LNG Report." July 12, 2023. https://www.igu.org/resources/lng2023-world-lng-report/.

68 IGU. "2023 World LNG Report." July 12, 2023. https://www.igu.org/resources/lng2023-world-lng-report/.

69 IGU. "2023 World LNG Report." July 12, 2023. https://www.igu.org/resources/lng2023-world-lng-report/. pp 67.

70 EU regulations covering the incorporation of shipping emissions into the EU ETS (Regulation (EU) 2015/757), most recently amended January 1, 2024, have the following methane slip factors for LNG carriers when using natural gas for propulsion: DFDE/TFDEs ("LNG Otto dual fuel medium speed"): 3.1%; XDFs and ME-GAs ("LNG Otto dual fuel slow speed"): 1.7%; ME-GIs ("LNG Diesel dual fuel slow speed"): 0.2%.

71 Balcombe, P., Heggo, D.A., and Harrison, M. 2022. "Total Methane and CO2 Emissions from Liquefied Natural Gas Carrier Ships: The First Primary Measurements." *Environmental Science & Technology* 56 (13): 9632–40. https://doi.org/10.1021/acs.est.2c01383.



Source: EIA, 2024, "U.S. Natural Gas Exports and Re-Exports by Country."

Figure 4-9. *Liquefied U.S. Natural Gas Exports by Vessel (MMscf)*

IV. NPC GHG LCA STUDY BOUNDARIES

Natural gas is diverse in source, supply chain, and end product. Some gas is sold to large-scale industrial users (such as domestic power plants and chemical plants). Other dispositions include transoceanic use enabled by liquefaction (LNG) and domestic, residential, and commercial use. The life cycle GHG emissions associated with each of these uses will vary due to the different operations on natural gas as it approaches the end of its life cycle. Typically, an energy LCA of an energy product would follow that product through end of life, but a partial scope may also be cradle to gate, which includes raw materials extraction up until it is directly transported to or used by the consumer. The analysis presented in this chapter characterizes U.S. natural gas supply chains to three gates (Figure 4-10):

- Gate 1: natural gas that reaches the end of transmission through high-pressure pipes where it could be directly delivered to large industrial customers or delivered to the next two gates
- Gate 2: inclusive of Gate 1, and delivered through the local distribution systems for use by residential or commercial customers, industrial customers, and other customers
- Gate 3: inclusive of Gate 1, but avoiding distribution, and instead delivered to liquefication and then transported as LNG to one of two archetypal destinations: Europe or China

The analyses that follow differentiate results according to these three gates and are focused specifically on U.S. natural gas supply chains up until they reach these three potential markets. Results are leveraged to better understand emissions associated with specific supply chains and emissions reduction scenarios.

The functional unit of each of these systems is 1 MJ[72] of natural gas (higher heating value basis) at the point of delivery. The boundary conditions used in this analysis exclude emissions at the large-scale end user (Gate 1), emissions at the distribution-system end user (Gate 2), and emissions at the regasification facility (Gate 3) (Figure 4-10).

Because this study is focused on natural gas and LNG, other hydrocarbons coproduced with natural gas, including crude oil and NGLs, are out of scope and, thus, emissions associated with these

72 One Megajoule is equal to 1 million Joules or 947.8 Btu.

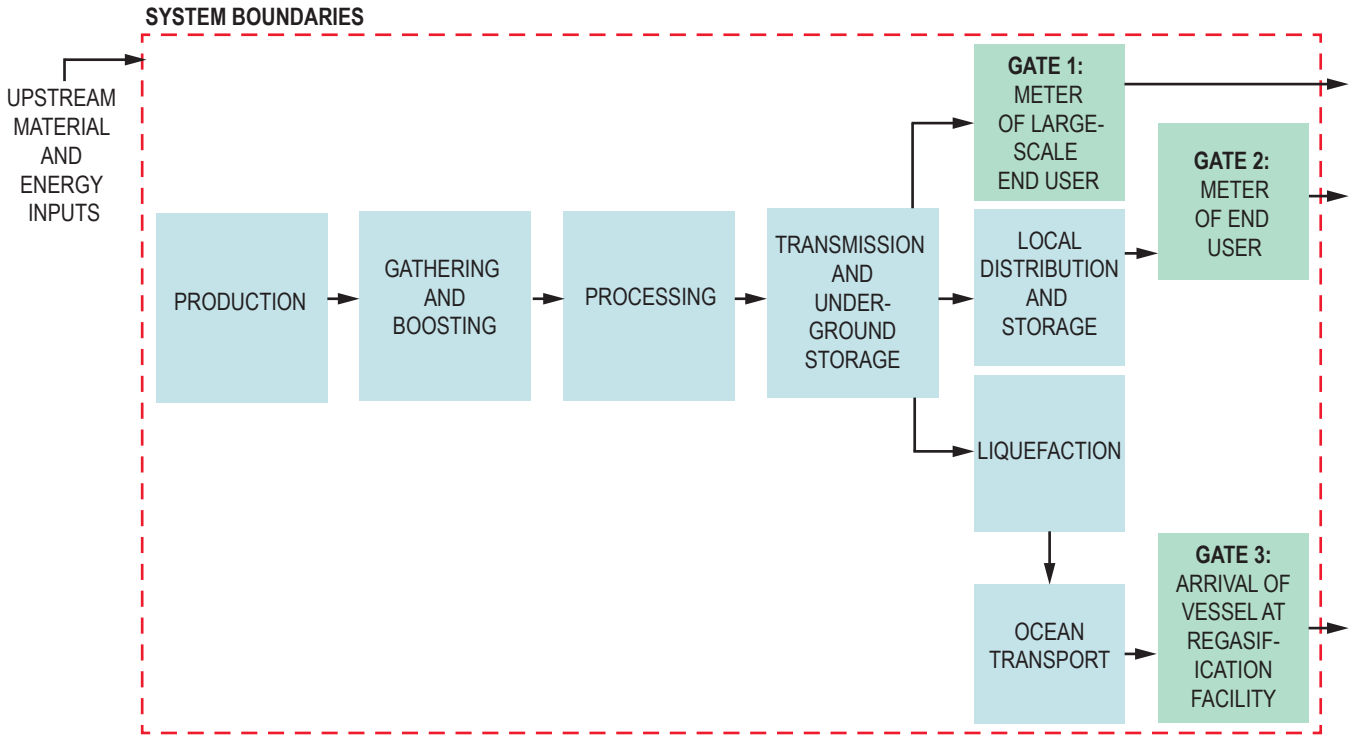


Figure 4-10. *Three Natural Gas Systems Considered in This Study and Their Gates*

hydrocarbon liquid products are excluded from the CFP of natural gas, but would be included in the CFP of those products. The partitioning of emissions to coproducts has been described in Section 1 as background with details related to this analysis detailed in Section 5.

Exploration activities and emissions associated with orphaned, abandoned, and undocumented wells are considered out of scope for this chapter because these wells do not contribute gas to customers. For exploration activities, the drilling of wells that are dry holes, or are otherwise not put into production, never become part of the producing supply chain. Orphaned, abandoned, and undocumented wells, likewise, do not contribute to the natural gas supply chain. While recent work has focused on better documenting and estimating methane emissions from these wells, they have not been widely incorporated into LCAs.[73, 74] Ultimately, based on available data, GHG emissions from exploration activities and orphaned or abandoned wells are expected to be a small fraction of the life cycle emissions associated with natural gas or LNG. The discussion on incorporating emissions associated with orphaned, abandoned, and undocumented wells and drilling of wells that do not produce gas (dry holes) into LCAs will be addressed in a separate topic paper.[75]

V. HARMONIZATION OF LIFE CYCLE GHG EMISSIONS IN U.S. NATURAL GAS SUPPLY CHAINS AND THE DEVELOPMENT OF A STREAMLINED NATURAL GAS LCA MODEL

Energy systems are some of the most complex products from a life cycle perspective, requiring researchers to spend years developing and maintaining LCA models. LCA software packages and open-source frameworks also exist, which allow

73 Environmental Defense Fund. "Plugging Orphan Wells Across the United States." October 14, 2021. https://www.edf.org/orphanwellmap.

74 Boutot, J., Peltz, A.S., McVay, R., and Kang, M. 2022. "Documented Orphaned Oil and Gas Wells across the United States." *Environmental Science & Technology* 56 (20): 14228–36. https://doi.org/10.1021/acs.est.2c03268.

75 "Orphan/Abandoned/Undocumented Wells." Topic Paper 4/ additional materials provided with "Charting the Course." 2024. Selina Roman-White, Cheniere Energy, Inc.; Sarah Izzat, Occidental Petroleum Corporation; Ian Laurenzi, Exxon Mobil Corporation, Chuck Brecher, Baker Hughes Company.

researchers to create and adjust certain parameter assumptions to create estimates of life cycle impacts. These approaches have been applied to natural gas as an energy product, and specifically to LNG. The number of studies and their diversity of approaches and assumptions have been challenging for decision-makers to support policy, investment, advocacy, and other decisions. Even with as many studies on natural gas and LNG that exist, complexities in LCA modeling and the resources and the expertise to run LCA models has limited the wider application of GHG LCAs for the natural gas supply chain by policymakers and companies.

The scope of this analysis is focused on GHG emissions within natural gas supply chains and focuses on how the harmonization process and simplified modeling results can inform decisions related to these emissions rather than other environmental impacts of the life cycle of natural gas supply chains.

To this end, this analysis has advanced knowledge to support decision-making in the following ways:

- The recent LCA literature relevant to current U.S. natural gas and LNG systems was systematically reviewed, and the findings of those studies consolidated (harmonized) to clarify central tendencies of disparate published estimates of life cycle GHG emissions.
- SLiNG-GHG was developed leveraging learnings from these studies (as well as additional input from selected, well-maintained LCA models, and expert judgment from subject matter experts) for the purpose of estimating life cycle GHG emissions intensities on a cradle-to-gate basis and illustrating the key drivers of GHG emissions in natural gas life cycles, including U.S. LNG systems, and creating a tool that can be used by nonexpert audiences to develop their own screening-level LCA (cradle-to-gate) estimates.

The first aim is accomplished through a meta-analysis of published life cycle GHG emissions estimates passing rigorous systematic review screens for quality, transparency, and relevance, a process established a decade ago in the LCA literature called harmonization.[76] Harmonization is a form of meta-analysis applied to LCAs to achieve a higher degree of consistency, and thus comparability, for results other than how they were originally published (e.g., via the modification of published LCA results to ensure consistent systems boundaries, modeling assumptions, etc.). Harmonization may help to reduce uncertainty around interpretation and use of life cycle emissions estimates and to make informed policymaking and research decisions.[77] Harmonization may inform a more robust central tendency for life cycle emissions in analyses examining systems-level changes, such as new destinations for LNG and global energy scenarios.[78, 79]

Considering the complexities of existing comprehensive LCA models, and limited uptake of the same by policymakers, oil and gas companies, investors, and other stakeholders, the SLiNG-GHG model was developed using Microsoft Excel to facilitate broader use by various stakeholders.[80] The study aimed to employ the best publicly available data sources compatible with LCA, while balancing timeline and resources. Guided by subject matter experts in: (1) the natural gas upstream and midstream (including LNG), and (2) LCA, the study team collaborated to identify a limited set (~70) of key model inputs (KMIs) to estimate emissions from 22 important emissions sources of methane and carbon dioxide across the supply chain. The SLiNG-GHG model reduces the complexities associated with typical LCA models and allows users who have limited life cycle modeling experience to develop screening-level estimates

76 Heath, Garvin A., and Margaret K. Mann. 2012. "Background and Reflections on the Life Cycle Assessment Harmonization Project." *Journal of Industrial Ecology* 16 (April): S8–11. https://doi.org/10.1111/j.1530-9290.2012.00478.x.

77 National Renewable Energy Laboratory. 2013. "Life Cycle Assessment Harmonization." 2013. https://www.nrel.gov/analysis/life-cycle-assessment.html.

78 Kasumu, A.S., Li, V., Coleman, J.W., Liendo, J., and Jordaan, S.M. 2018. "Country-Level Life Cycle Assessment of Greenhouse Gas Emissions from Liquefied Natural Gas Trade for Electricity Generation." *Environmental Science & Technology* 52 (4): 1735–46. https://doi.org/10.1021/acs.est.7b05298.

79 Surana, Kavita, and Sarah M. Jordaan. 2019. "The Climate Mitigation Opportunity behind Global Power Transmission and Distribution." *Nature Climate Change* 9 (9): 660–65. https://doi.org/10.1038/s41558-019-0544-3.3.

80 McGill, ETAPA background on Life Cycle Assessment: https://etapa.research.mcgill.ca/projects/sling-ghg.

of life cycle GHG emissions for a variety of U.S.-specific natural gas supply chains and what-if scenarios.

While the model allows users to tailor their evaluation to their specific case by adjusting any input value for each KMI, the user should clearly recognize the limitations of such a streamlined model and may want to consider the use of a more comprehensive LCA model to meet their end goals. Moreover, the model should also not be used in place of an applicable jurisdiction-specific, legally required model. As described further herein, the model, by design, incorporates a subset of the CO_2 emissions sources in each stage, thereby not accounting for all relevant CO_2 emissions sources in each stage of the supply chain. The choice of CO_2 emissions sources is meant to capture significant contributors; the industry and research subject matter experts deem the impact of this simplification to be minor, confirmed through comparison of SLiNG-GHG results to those from detailed LCA model. Methane, on the other hand, is aggregated at coarser stage level and therefore, by design, should account for all methane emissions sources or unit processes within each stage of the supply chain.

It is important to recognize that the default values used for each KMI as part of this simplified model can be replaced with completely customized ones to match user's operations or study goals. To facilitate investigation of the sensitivity of estimates generated by the model to assumptions regarding methane emissions, users may enter KMIs based on measurement studies of their choice. Estimates of the life cycle GHG emissions associated with natural gas pathways in this report may differ from estimates generated by other users or other decision contexts. Documentation of the model is provided to allow others to use the model independently.

This chapter also reports the results of the application of the model for natural gas and LNG emissions pathways/supply chain cases described later in this section. The inputs employed for the relevant KMIs associated with these pathways and supply chains are based on review of literature and input from subject matter experts and documented further in Appendices E-11 and E-12.

Finally, as noted above, like other LCAs, with rare exception, the default input values in the model are not based on direct emissions measurements conducted specifically for this study. This study group is not aware of an LCA study that has exclusively employed measurements to account for emissions from each unit process in each stage of the natural gas life cycle from drilling and completion through end use. There have been certain studies that have incorporated measurement-informed datasets from individual life cycle stages or conducted sensitivity analysis by using measurement-informed datasets.[81, 82, 83] Such an ideal was not possible because no new direct emissions measurements were made for this study. It is widely recognized by research, advocacy, and policy communities that there are discrepancies between the results of methane emissions measurement studies and estimates made using EPA methodologies (e.g., starting with Brandt et al., 2012).[84] Guidance for incorporating measurements within LCA has not been established because the research community has only recently started to recognize the challenges in interpreting measurements conducted at different spatial and temporal scales within the context of process-based LCA frameworks (leading to the study's recommendation to develop the same). Additional details of these challenges are documented later in this section.

To estimate methane emissions over the natural gas life cycle, some practitioners (e.g., NETL)

81 Contreras, W., Hardy, C., Tovar, K., Piwetz, A.M., Harris, C.R., Tullos, E.E., Bymaster, A., McMichael, J., and Laurenzi, I.J. 2021. "Life Cycle Greenhouse Gas Emissions of Crude Oil and Natural Gas from the Delaware Basin." *Journal of Cleaner Production*, October, 129530. https://doi.org/10.1016/j.jclepro.2021.129530.

82 Roman-White, S.A., Littlefield, J.A., Fleury, K.G., Allen, D.T., Balcombe, P., Konschnik, K.E., Ewing, J., Ross, G.B., and George, F. 2021. "LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting." *ACS Sustainable Chemistry & Engineering* 9 (32): 10857–67. https://doi.org/10.1021/acssuschemeng.1c03307.

83 Zhu, Y., Allen, D., and Ravikumar, A. "Geospatial Life Cycle Analysis of Greenhouse Gas Emissions from US Liquefied Natural Gas Supply Chains." ChemRxiv. 2024; doi:10.26434/chemrxiv-2024-9v8dw. This content is a preprint and has not been peer-reviewed.

84 Brandt, A.R., Heath, G.A., Kort, E.A., O'Sullivan, F., Petron, G., Jordaan, S.M., Tans, P., et al. 2014. "Methane Leaks from North American Natural Gas Systems." *Science* 343 (6172): 733–35. https://doi.org/10.1126/science.1247045.

have used the EPA GHGI or data from the EPA GHGRP as their primary data source. Their virtues are that they are publicly available, source and supply chain stage oriented, and updated annually. The EPA has continued to make progress incorporating empirical data from measurement studies into its inventories and it is anticipated that the EPA methane emissions datasets will progressively become better with updates to the GHGRP regulations and plans from the U.S. Government to improve GHG data via the GHG Data Center,[85] initiatives from the International Methane Emissions Observatory (IMEO),[86] and other institutions.[87] Recent peer-reviewed LCAs have incorporated methane emissions measurements for certain unit processes within the production stage.[88, 89]

A. Harmonization of Prior Published Estimates of Life Cycle GHG Emissions in U.S. Natural Gas and LNG Supply Chains

The harmonization procedure is based on the approaches developed by the NREL for electricity generation technologies in 2012,[90, 91] including two studies on natural gas-fired electricity generation.[92, 93] The harmonization performed herein updates these prior studies by focusing on publications between October 2016 and October 2022.

Harmonization includes two stages: first, systematic literature review, and second, meta-analysis. Since the first LCA Harmonization studies, methods for systematic literature review have become further described in global guidance.[94, 95] The present analysis improved methods for systematic review using these and more recent studies.[96, 97] The goal of systematic review is to identify all published sources within the scope of study. This requires steps of identification and then screening of literature from bibliographic databases to ensure only those relevant to the study scope are retained.

The meta-analysis stage mathematically adjusts the published estimates of life cycle GHG emissions to improve comparability across studies. Elaborated further elsewhere in this chapter, examples include enforcing consistent system boundaries and GWPs applied to the different GHGs, like methane. Importantly, harmonization does not assume the prior published results are incorrect; rather, it adjusts legitimate

85 U.S. GHG Center: https://earth.gov/ghgcenter.

86 United Nations Environment Programme International Methane Emissions Observatory: https://www.unep.org/explore-topics/energy/what-we-do/methane/imeo.

87 Energy Emissions Modeling and Data Lab, EEMDL: https://www.eemdl.utexas.edu/.

88 Contreras, W., Hardy, C., Tovar, K., Piwetz, A.M., Harris, C.R., Tullos, E.E., Bymaster, A., McMichael, J., and Laurenzi, I.J. 2021. "Life Cycle Greenhouse Gas Emissions of Crude Oil and Natural Gas from the Delaware Basin." *Journal of Cleaner Production*, October, 129530. https://doi.org/10.1016/j.jclepro.2021.129530.

89 Roman-White, S.A., Littlefield, J.A., Fleury, K.G., Allen, D.T., Balcombe, P., Konschnik, K.E., Ewing, J., Ross, G.B., and George, F. 2021. "LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting." *ACS Sustainable Chemistry & Engineering* 9 (32): 10857–67. https://doi.org/10.1021/acssuschemeng.1c03307.

90 National Renewable Energy Laboratory. 2013. "Life Cycle Assessment Harmonization." 2013. https://www.nrel.gov/analysis/life-cycle-assessment.html.

91 Brandão, M., Heath, G., and Cooper, J. 2012. "What Can Meta-Analyses Tell Us about the Reliability of Life Cycle Assessment for Decision Support?" *Journal of Industrial Ecology* 16 (April): S3–7. https://doi.org/10.1111/j.1530-9290.2012.00477.x.

92 O'Donoughue, P.R., Heath, G.A., Dolan, S.L., and Vorum, M. 2014. "Life Cycle Greenhouse Gas Emissions of Electricity Generated from Conventionally Produced Natural Gas." *Journal of Industrial Ecology* 18 (1): 125–44. https://doi.org/10.1111/jiec.12084.

93 Heath, G.A., O'Donoughue, P., Arent, D.J., and Bazilian, M. 2014. "Harmonization of Initial Estimates of Shale Gas Life Cycle Greenhouse Gas Emissions for Electric Power Generation." *Proceedings of the National Academy of Sciences* 111 (31): E3167–76. https://doi.org/10.1073/pnas.1309334111.

94 Cochrane Library. 2023. "About the Cochrane Database of Systematic Reviews | Cochrane Library." https://www.cochranelibrary.com/cdsr/about-cdsr.

95 Page, M.J., McKenzie, J.E., Bossuyt, P.M., Boutron, I., Hoffmann, T.C., Mulrow, C.D., Shamseer, L., et al. 2021. "The PRISMA 2020 Statement: An Updated Guideline for Reporting Systematic Reviews." *British Medical Journal* 372 (71). https://doi.org/10.1136/bmj.n71.1

96 Heath, G.A., Ravikumar, D., Hansen, B., and Kupets, E. 2022. "A Critical Review of the Circular Economy for Lithium-Ion Batteries and Photovoltaic Modules – Status, Challenges, and Opportunities." *Journal of the Air & Waste Management Association* 72 (6): 478–539. https://doi.org/10.1080/10962247.2022.2068878.

97 Jordaan, S.M., Cory Combs, and Edeltraud Guenther. 2021. "Life Cycle Assessment of Electricity Generation: A Systematic Review of Spatiotemporal Methods." *Advances in Applied Energy* 3 (August): 100058. https://doi.org/10.1016/j.adapen.2021.100058.

differences in methods for improved consistency and comparability, which allows for more robust understanding of the central tendency of prior estimates of life cycle GHG emissions. It can also help to illuminate parameters most influential to life cycle GHG emissions.

1. Systematic Literature Review

The LCA literature was systematically assessed via data mining of Google Scholar following the methods described in Jordaan et al.,[98] which methodologically compliments those of Heath et al.,[99] both of which are leveraged in this study.

The keywords used for literature collection were selected by the authors, informed by prior harmonization studies with feedback from subject matter experts participating in the NPC study (Refer to Table E-1 in Appendix E-1 for the list of keywords used for literature search). Keywords were established in synonym clusters, centering on: (1) natural gas or LNG or products that use natural gas or LNG as a fuel input (e.g., electricity generation, heat) and (2) LCA. The number of publications identified from these keywords defines the "universe" of publications then subjected to screening.

a. Screening Criteria

Following the successive screening approach of Heath et al., (2014), a series of objective screens was established. The process was iterative to ensure accuracy and completeness. The philosophy of the series of screens is to move from easier and faster identification of failing characteristics to ones that are more complex and take longer to judge. The full series of screens are detailed in Appendix E-2. Key criteria are described here in summary, including:

- **Temporal vintage of the study.** Only studies published since 2016 were considered in order to best represent the U.S. natural gas system by both (1) occurring after the EPA updated the New Source Performance Standards and Permitting Requirements (NSPS) rules for oil and gas industry,[100] and (2) to ensure that models used relatively more recent data.
- **Geographic location of the study.** Only studies with the natural gas supply chains in the United States were included.
- **Product studied.** Only studies that focused on natural gas or LNG, or products where natural gas or LNG is used as a fuel (e.g., electricity, heat) were included. If a product derived from natural gas/LNG was the focus, then the study had to have reported the natural gas/LNG supply chain separately and in detail. Excluded were LCAs whose final product was other energy carriers, as well as chemicals or plastics.
- **Quality and transparency of LCA methods.** Regarding quality, LCAs stating that they followed international guidelines such as the *ISO 14040*, *14044*, and *14067* standards were accepted. Publications not stating adherence to those standards but using LCA models developed at U.S. national laboratories, oil and gas producers, and academia and published by publishers using peer-review processes (such as academic journals or national laboratories) were accepted. Most important was transparency in the reporting of methods, assumptions, and technology descriptions such that there was a high degree of confidence in the results and their potential to be reproduced.

Screening started at the level of articles and proceeded to the level of individual estimates.

The universe of literature identified as potentially relevant to the scope of this study was 2,229 articles in total (after removal of duplicates). After four stages of screening (Appendix E-2 details each screening stage and their order), the study pool had 16 articles, or 0.7% of the initial study pool size (Figure 4-11). A record was created of passing or failing each screen for every publication reviewed.

98 Jordaan, S.M., Combs, C., and Guenther, E. 2021. "Life Cycle Assessment of Electricity Generation: A Systematic Review of Spatiotemporal Methods." Advances in Applied Energy 3 (August): 100058. https://doi.org/10.1016/j.adapen.2021.100058.

99 Heath, G.A., O'Donoughue, P., Arent, D.J., and Bazilian, M. 2014. "Harmonization of Initial Estimates of Shale Gas Life Cycle Greenhouse Gas Emissions for Electric Power Generation." *Proceedings of the National Academy of Sciences* 111 (31): E3167–76. https://doi.org/10.1073/pnas.1309334111.

100 EPA. 2016. "New Source Performance Standards and Permitting Requirements." September 27, 2016. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/new-source-performance-standards-and#Final.

It should be noted that there were no criteria to include or exclude based on choice of underlying LCA model or LCI database. Rather, screening was focused on ensuring high quality of the LCA methods used. Consequently, publications using LCA models developed at U.S. national labs, oil and gas producers, and academia are part of the final pool of 16.

b. Summary of Studies in the Final Study Pool

While the process of harmonizing the life cycle estimates from the literature brings a higher degree of consistency and comparability, it must be understood that the estimates are still quite different in nature, with variability caused by numerous factors. To begin with, the studies differ in their primary objective and the product systems on which they focus. Case in point, out of the 16 studies that passed all the screens, five focus on electricity as the end product, two studies focus on natural gas supply chains, another five studies focus on LNG products (of which two explore LNG as a marine fuel), and three focus on natural gas-based fuels for road transportation. Note that for the purpose of both harmonization and use of these studies to develop and populate SLiNG-GHG, end use was removed to align with the NPC study boundary.

Moreover, the studies differ in terms of the type of natural gas analyzed as well, with 14 studies in the final study pool focusing on both conventional and unconventional natural gas whereas the remaining two focus on unconventional gas exclusively. Out of the 14 studies, only four explicitly mention the type of unconventional gas (shale/tight, etc.) focused on.

Estimates from the studies also vary in the geographical region they represent, with 13 studies out of the 16 representing a national average, two representing different basins from the United States (Appalachia and Delaware) and one representing a mixture of basins. The studies also differ in their key methane data sources, with six studies out of 16 using EPA sources blended with published measurements, four solely relying on EPA, three relying on LCA datasets that include published measurements, and one each relying on direct measurements and common LCI datasets (Ecoinvent).

The system boundaries differ across different studies as well, with estimates of seven studies covering Production to LNG delivery, four studies

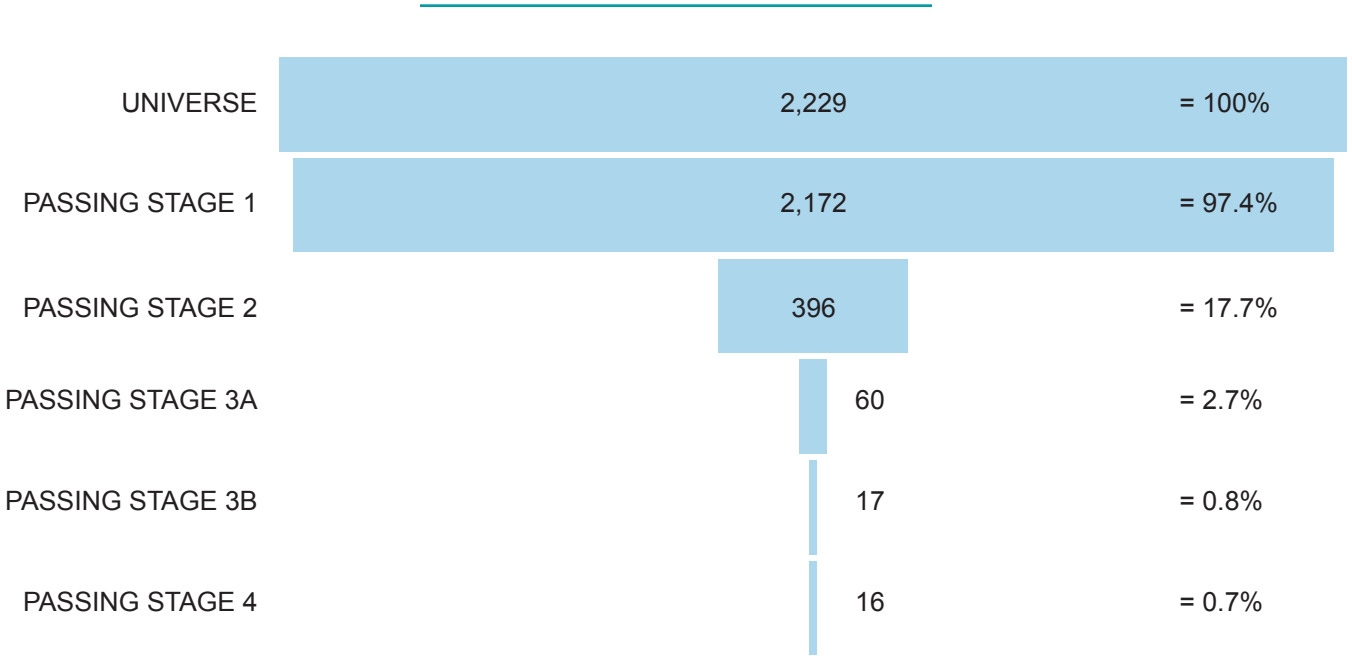


Figure 4-11. *Number of Articles Passing Each Stage, Using the Screening Criteria Outlined in Appendix E-2*

covering Production to Distribution, three studies covering Production to Transmission, and one each for Production to Processing and Recovery (Preproduction and Production). Similar to how the difference in end product was adjusted to ensure alignment with the NPC study boundaries, system boundaries were also adjusted in the harmonization process to align with the NPC study gates.

Please review Appendix E-3 for further details.

2. Harmonization

Harmonization enables more consistent comparison of the results of multiple studies. It is applied to each study estimate (not at the level of a publication, which might produce multiple estimates based on different scenarios, geographies, sensitivity cases, etc.). Harmonization enhances commensurability by ensuring consistent units are used and consistent system boundaries. Consistency relates to both the numerator and denominator of the carbon intensity (i.e., g CO_2e as numerator and MJ natural gas delivered to end of gate as denominator). Within the numerator, the study ensured consistency in which emissions sources are included (system boundary) as well as the GWP employed to translate masses of emissions of different GHGs to CO_2 equivalents.[101] For the denominator, harmonization was applied again to system boundary, here specifically to the stagewise losses of natural gas (from both emissions and use of the gas through each supply chain stage), and conversion of various normalization units employed in different studies (e.g., various energy units of measure).

To prepare for harmonization, life cycle GHG emissions estimates and important estimate-level characteristics and methods from studies passing systematic review screens were extracted. For instance, the system boundaries of each estimate and collection of stagewise supply chain GHG emissions and natural gas losses when available. Study and estimate characteristics are summarized in Appendix E-3.

It is commonly understood by the LCA community that for systems combusting fossil fuels,[102] GHG emissions from unabated combustion will be the highest GHG emissions stage in the life cycle, and that the efficiency of combustion (of the end product) has a leveraging effect on the amount of emissions from the fuel cycle. Without inclusion of end use in the scope of this study, several harmonization steps applied in the prior natural gas harmonization studies were not applicable here (e.g., combustion efficiency in a power plant).

Recalling the importance of coproduct allocation in LCAs of multiproduct systems (Section I.C.), each study was examined in terms of how they treated coproduct allocation: all 16 studies either applied coproduct allocation or considered natural gas only. Thus, their estimates did not require coproduct allocation in the harmonization process.

The steps of harmonization proceeded in the following order:

1. Alignment to gate boundaries, including adders for when distribution or LNG shipping was missing
2. Use of consistent GWP100 and GWP20 values
3. Inclusion of important natural gas supply chain processes: preproduction and liquids unloading

The first stage of harmonization was aligning estimates to three different gates. For estimates that have a system boundary that falls short of the harmonized gate, "adders" were developed following the methodology in prior harmonization studies based on averages for stage-specific emissions reported by other studies passing the systematic review screens. This is further described in Appendix E-4. All studies passing screens reported results for Gate 1; adders were only applicable for those studies that didn't include

101 Note that literature review screening criteria required LCAs to consider both CO_2 and CH_4. Some LCAs also considered N_2O. This was left as an unharmonized study difference; N_2O makes negligible contribution to natural gas life cycle GHG emissions. The GWP for N_2O, which has changed over time, was likewise left unharmonized for those studies that did account for N_2O.

102 Note that this does not apply to hydrogen derived from fossil fuels.

distribution (Gate 2) or LNG shipping portion of Gate 3.[103]

Second, the estimates with GHG breakdown (CO_2 and CH_4) were then harmonized to GWPs from IPCC AR5 (100 yr and 20 yr), consistent with the selection of AR5 for use in this study. AR5 GWPs are used here to be consistent with EPA data and inventories on which U.S. reduction commitments are based. The selection of AR5 is discussed further in Chapter 1. This harmonization step is further described in Appendix E-4.

The last step of harmonization involved adding average estimates of emissions for activities which were sometimes missing from LCAs—preproduction and liquids unloading—using an analogous method as for the gate harmonization step (distribution and LNG shipping adders). This is further described in Appendix E-4, which also reports how each harmonization step was applied to each individual estimate.

Figure 4-12a and 4-12b display the harmonized results for the three gates in GWP100 and GWP20, respectively. As expected, life cycle GHG emissions across each gate increase from transmission to LNG shipping. A comparison of published to harmonized estimated, both in graphical and tabular form is in Appendix E-5.

a. Harmonization of Methane Emissions Rates: Methodology and Results

In this study, published methane emissions rates are harmonized for three gate boundaries (e.g., Gate 1-Production to Transmission, Gate 2-Production to Distribution, and Gate 3-Production to Destination of LNG Shipping). Reporting stagewise methane emissions rates in this manner enables standardized comparisons and benchmarking across methane emissions rates. For each study passing the systematic review screening, published methane emissions rates were documented and further harmonized to a reference flow of one MJ of delivered natural gas on an HHV basis. The process of harmonization involved accounting for differences in natural gas composition, HHVs, conversion between physical units (mass, volume, and energy), as well as natural gas loss/consumption rates for each segment of the natural gas supply chain through delivery. The latter was estimated based on published data from the EIA and used to convert methane emissions rates from stage-level natural gas throughput to a common basis of natural gas delivered to the gate. Please refer to Appendix E-6 for a complete list of published methane emissions rates, as well as workflow elements and assumptions used during harmonization of methane emissions rates.

Table 4-1 provides summary statistics for harmonized methane emissions rates cumulative to the end of each of the gate boundaries to illustrate their relative emissions contributions at each gate. In Table 4-1, the harmonized CH_4 emissions rate for Gate 3 (Production to Destination of LNG Shipping) is the lowest of the three gate boundaries. Potential reasons for this could be attributed to different sets of studies that reported results for each gate and the lower sample size of studies for Gate 3 as compared to the other two gates, or potential for more methane emissions from the distribution segment relative to the shipping segment as percentage of natural gas or LNG delivered at the end of the gate.

B. SLiNG-GHG Model

1. Methodology

The SLiNG-GHG model was developed using the decision logic outlined in Figure 4-13. The literature screened during harmonization was reviewed to identify studies that undertook some kind of quantified analysis to identify parameters that most significantly influence life cycle GHG emissions, including contribution analyses, sensitivity analyses, and uncertainty analyses. Results of these various analyses were synthesized and combined with judgment of the industry, NGO, and academic experts within the NPC study team yielding approximately 70 KMIs that represent 22 key sources of GHG emissions (unit processes). Material balance equations were then

103 Note that studies were not harmonized in Gate 3 results for transmission distance because it was not a screening criterion to only accept studies that investigated a specific geography. LNG shipping distance was also not harmonized, though the shipping destination of either U.K. or Asia was selected. If a study required adding this portion of the supply chain, then a common, average estimate for GHG emissions was used, which inherently enforces consistency.

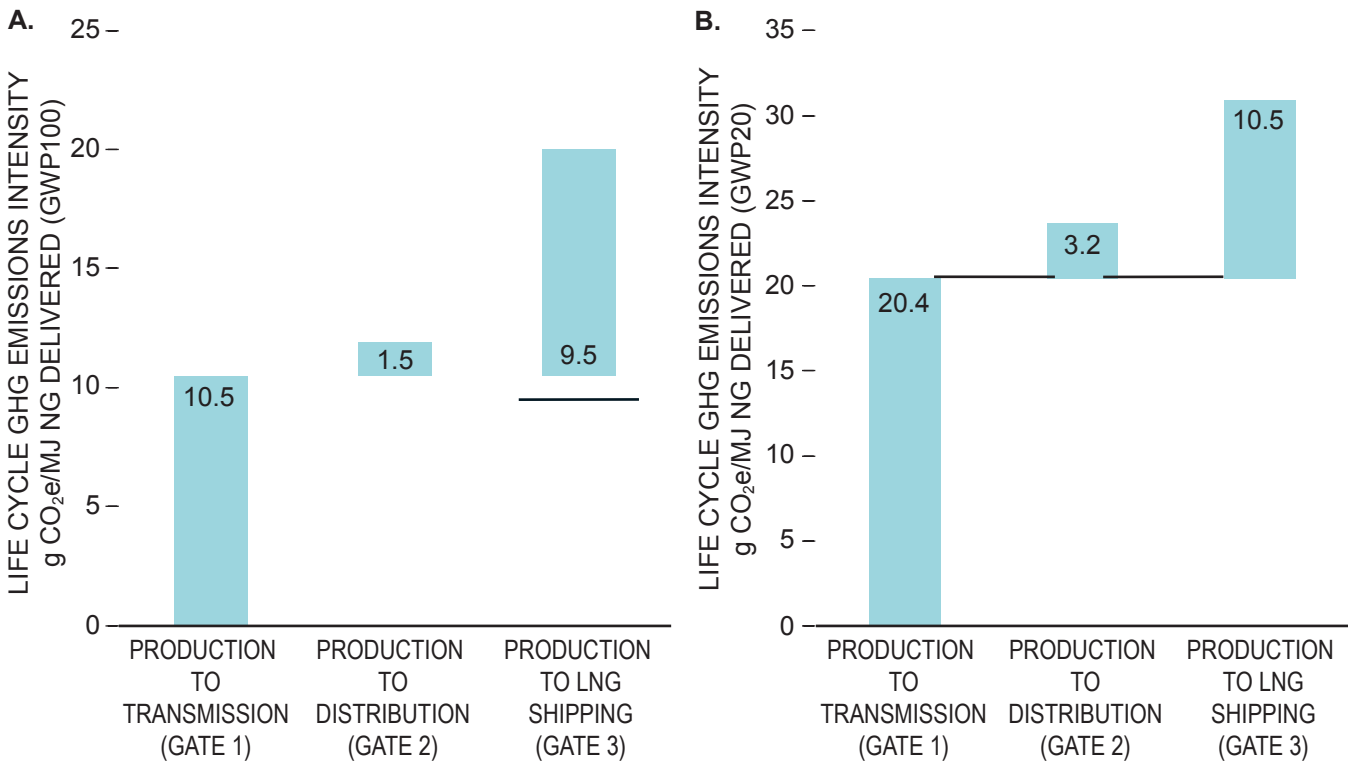


Figure 4-12a – b. *Increase in Emissions from Transmission Displaying the Mean Harmonized Estimates as Developed in This Study for (a) GWP100, and (b) GWP20*

constructed to form the basis of the streamlined LCA model, utilizing the KMIs to estimate flows of gas and other hydrocarbon products as well as emissions. Other key principles, such as energy-based coproduct allocation, were followed in the model development. Appendix E-7 defines each of the ~70 KMIs across the supply chain stages within scope of the NPC study, along with its Reference case value (and source thereof). The model was developed to pair with the scope and boundary of this study, and thus does not include emissions from operations past the gates of the three boundaries examined here. Thus, emissions from end-use consumption of natural gas are not included, but such unit processes could be added to the model in the future.

	Harmonized CH_4 Emissions Rate, Reported as % (g CH_4/G NG Delivered to End of Gate)		
	Gate 1 (Production to Transmission)	Gate 2 (Production to Distribution)	Gate 3 (Production to Destination of LNG Shipping)
Number of studies	8	10	4
Mean	0.95%	1.16%	0.93%
Standard deviation	0.34%	0.28%	0.19%
Min	0.43%	0.62%	0.74%
Median	0.97%	1.12%	0.93%
Max	1.50%	1.70%	1.20%

Table 4-1. *Harmonized Natural Gas Supply Chain Methane Emissions (g CH_4 Emitted/g Natural Gas Delivered to End of Gate) as per Study's Reported Boundaries (U.S. Average)*

Formulas were developed from the selected key model inputs (using KMIs such as CH_4 emissions rates and known values such as natural gas higher heating value) to quantify CH_4 and CO_2 emissions from selected sources in a stage. The default KMIs used in the model Reference case are included in Appendix E-7.

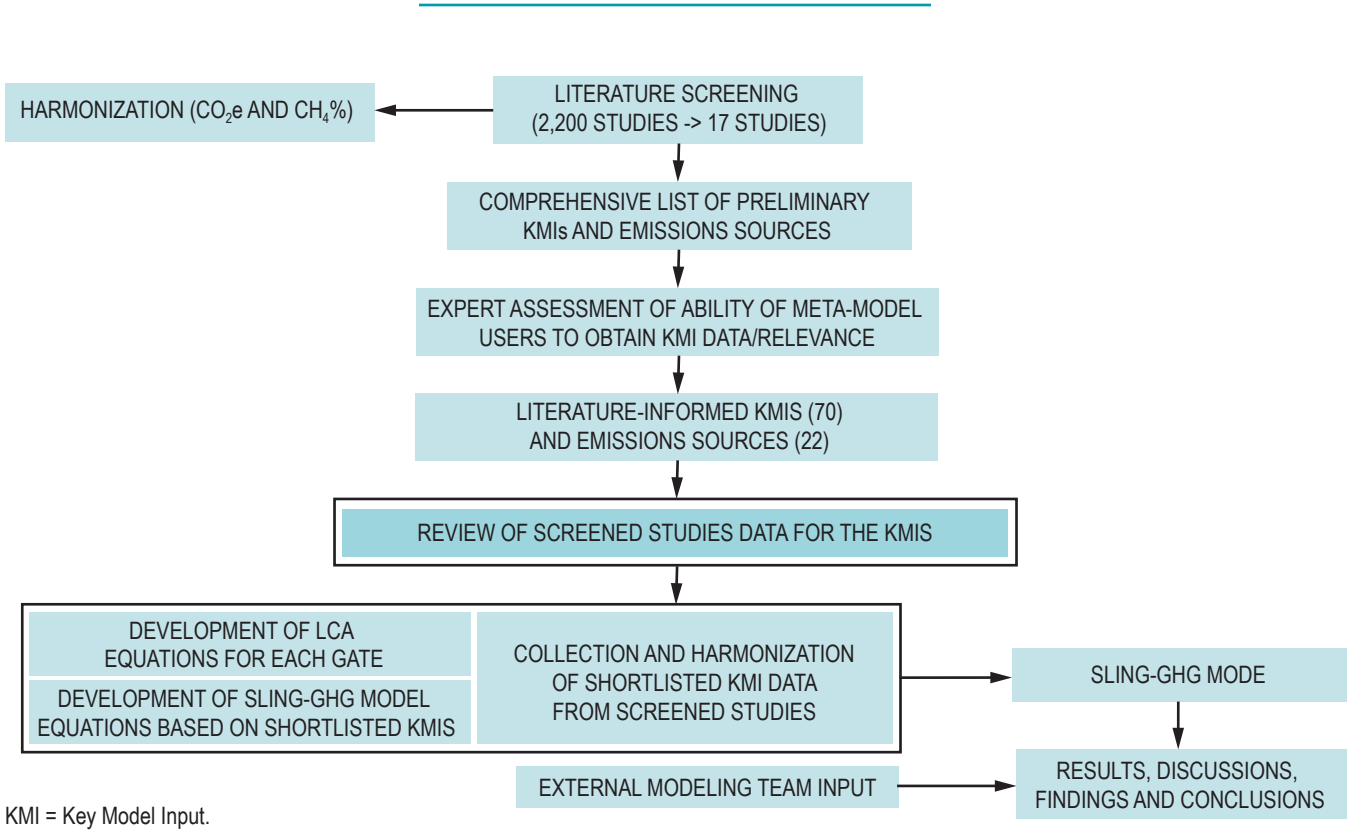
Once the formulas to quantify the emissions were developed, data were collected for all required data inputs and KMIs, which was from a combination of:

- Peer-reviewed literature (primary source)
- Reputable, publicly available sources from government agencies such as AP 42 catalog of emissions factors
- Outputs of harmonization work (the latter was used for methane emissions rates or methane leakage)
- Baseline input values were finalized by technology subject matter experts (reported in Appendix E-7).

2. External Modeling Teams

The 16 studies identified in Appendix E-3 represented the work of 10 separate institutions, including researchers from national labs, universities, and industry. To test the robustness of the streamlined LCA model relative to other detailed LCA models, the principal investigators from these institutions (hereafter referred to as "external modeling teams") were interviewed to get more background and clarity on their studies. Five requests were made to the external modeling teams:

- A fresh set of results for instances in which they updated their models, parameters, or data but had not published their latest results
- Modify their scenarios to reflect the three gates of our analysis (gas through transmission, distribution, and landed LNG)
- Results converted to the basis of 1 MJ of delivered natural gas on an HHV basis (some studies use an LHV basis)



KMI = Key Model Input.

Figure 4-13. *The Decision Logic Used for the Development of the SLiNG-GHG Model*

- Stratify their supply chains according to the stages employed by this analysis (production, G&B, processing, transmission, distribution, and the LNG segment)
- Either disaggregate their GHG metrics into individual species (CO_2, CH_4, and N_2O) or use factors consistent with IPCC AR5 100-year GWPs and share results from reruns of their models

Of the four external modeling teams that assisted with this study, some employed component buildups of emissions sources with detailed parameterization, some conducted careful data collection and scaling of measurements to a life cycle basis, and others used a hybrid approach that combined both. In concert, all approaches, after the scope and boundary reconciliation facilitated by the four interviews, provide diverse perspectives on natural gas supply chain GHG emissions, but in the end a common conclusion.

3. Comparative Analysis of SLiNG-GHG Model Results with Harmonization Study and External Modeling Teams

Four of the external modeling teams provided outputs from their complex LCA models and the central estimates (mean) of the external models are compared with the GHG LCA estimates from the streamlined LCA model. As shown in Figure 4-14 and Figure 4-15, the streamlined model results fall well within the range of GHG emissions intensities estimated from external modeling teams. Also, the study finds relatively reasonable alignment between the central estimates from the Reference case model and the harmonization work.

As shown in Figure 4-14 and Figure 4-15, the SLiNG-GHG model results using default KMIs provided in Appendix E-7 falls near the middle of the range of national life cycle GHG emissions intensities estimated from external modeling teams. Emissions intensities in the national Reference case model results differ from that of the harmonized estimates because of differences in the parameterization of the models—the streamlined model uses approximately 70 KMIs to represent 22 unique sources of emissions, or unit processes, whereas the LCA models that were used in the 16 harmonized studies included a much larger number of parameters that correspond to more than 100 discrete emissions sources and more than 1,600 KMIs in one, external, full-scale LCA model. Despite its limitations, the study finds that the model provides reasonable, screening-level estimates of life cycle GHG emissions for natural gas and LNG when compared against other models.

There are a few potential reasons why the Reference case model results are lower than the mean of the harmonized studies, the most likely being that complex LCA models include more than 100 discrete emissions sources whereas the streamlined model focuses on 22 unit processes. However, it is important to recognize that the streamlined model is aimed at representing the current state of U.S. natural gas, whereas the studies included in the harmonization effort represented a range of data vintages and supply chain scopes. As noted earlier, the model, by design, incorporates all methane emissions process units from each stage of the supply chain and is represented by a methane intensity KMI. Therefore, structural differences between a comprehensive LCA and the streamlined model primarily lie with the number of CO_2-related unit processes incorporated into each model. Of course, the input values to each KMI or unit process in the LCAs also drive the differences between the streamlined LCA model and the external modeling teams. None of the external modeling LCAs reviewed as part of this study fully incorporates measurement-informed GHG emissions datasets as inputs to the process units or KMIs across the supply chain. Despite its limitations, the streamlined LCA model provides reasonable, screening-level estimates of life cycle GHG emissions for natural gas and LNG.

Future enhancements on the model could focus on modeling additional sources of CO_2, but with careful attention to maintaining the simplicity of the model by focusing on a relatively small number of KMIs that are widely understood by public policymakers, industry, NGOs, and other potential users of the model. Further, the study recognizes that the 22 key sources of GHG emissions was informed by the current state of the published LCA literature, and further harmonization efforts may need to be completed in the future as more

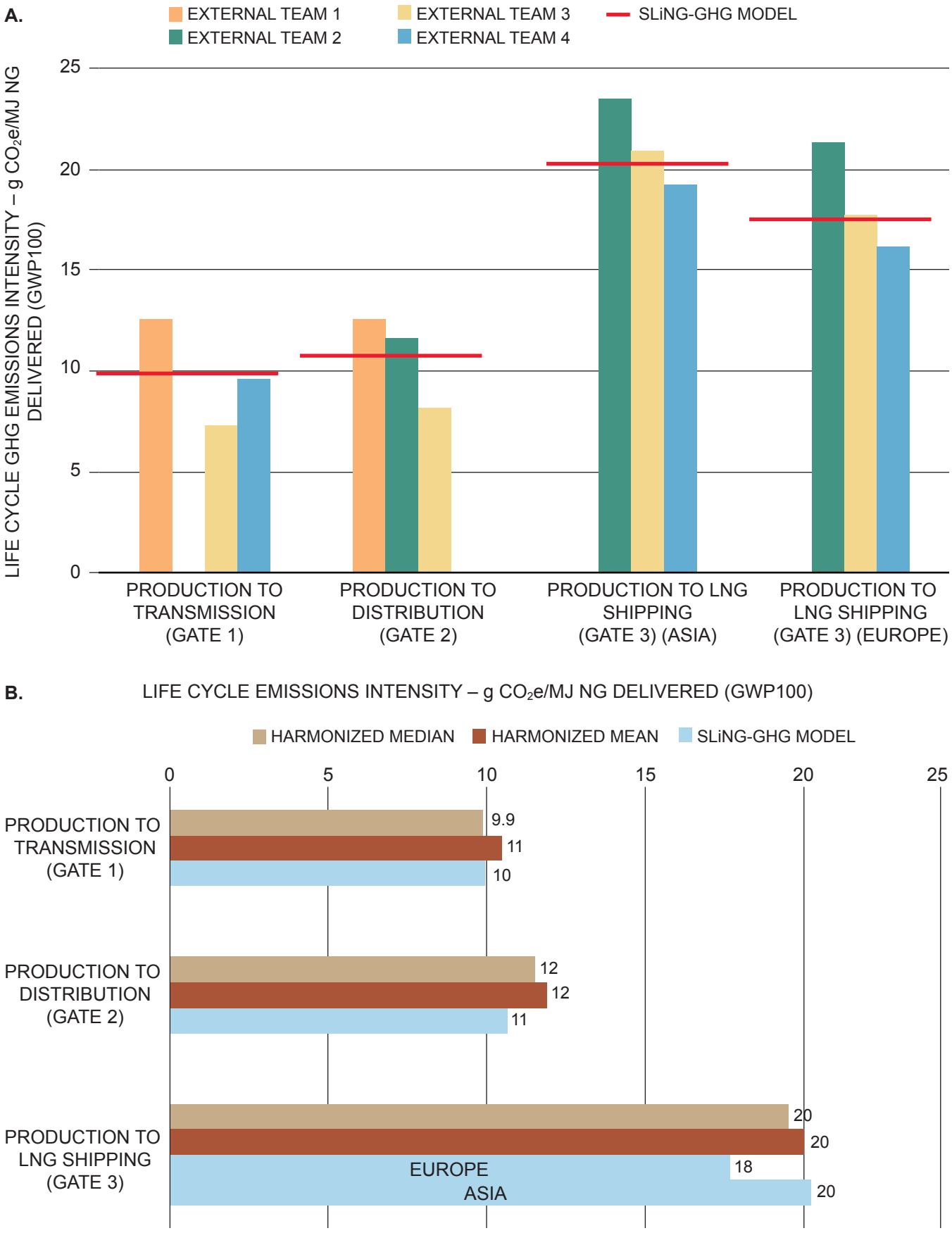


Figure 4-14a–b. *Comparison of SLiNG-GHG Model Results with (a) External Modeling Teams and (b) Harmonization Central Tendencies (GWP100)*

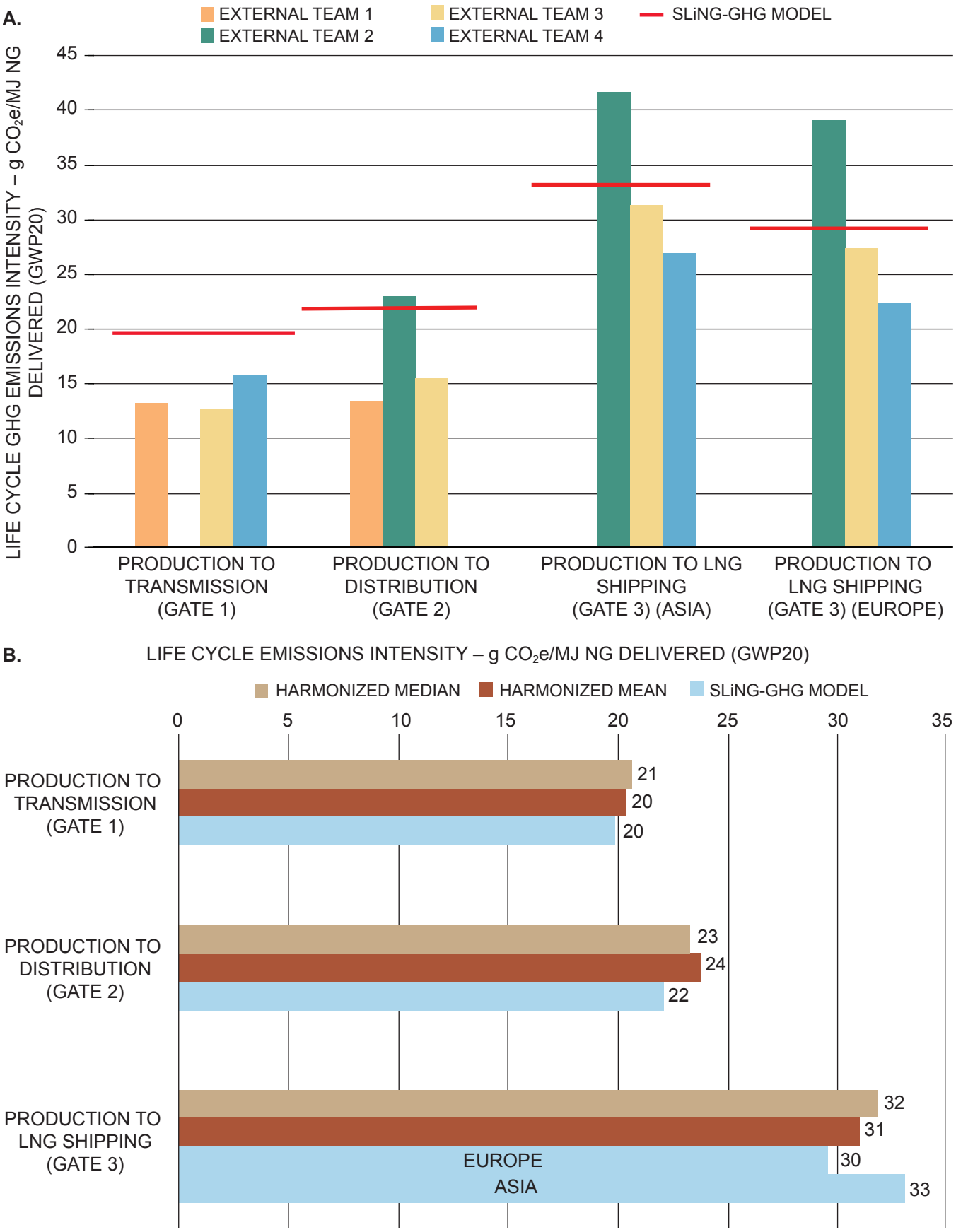


Figure 4-15a–b. *Comparison of SLiNG-GHG Model Results with (a) External Modeling Teams and (b) Harmonization Central Tendencies (GWP20)*

studies with improved modeling and empirical data become available.

Comparison of GWP20 and GWP100 results provides interesting insights into the impact of methane on overall results. The model Reference case GWP20 results are more than 2x higher than the GWP100 results for the domestic gas scenarios (Gates 1 and 2) and about 60%–70% higher under the LNG export cases. In comparison, the GWP20 harmonized means under the domestic gas cases are also almost double the GWP100 means and are about 55% higher for the LNG cases. The model GWP20 to GWP100 differences are aligned closer with similar comparisons of results from external modeling Team 2 for Gate 1 and Gate 2. For the LNG export cases, Team 2 has the GWP20 results 76%–83% higher than the GWP100 results. External modeling Teams 3 and 4 report GWP20 differences relative to GWP100 of about 65%–88% for domestic cases, and 40%–54% for the LNG cases. The results from external modeling Team 1 show only a 6% difference between the GWP20 and GWP100. This analysis clearly shows that the model Reference case results may be overestimating the impact of methane emissions relative to other complex LCA models, but well within reasonable levels of most external LCA models. Additional methane contribution analysis is discussed in this section. Recognizing limitations of the model in that it focuses on a subset of impactful KMI, the study finds the streamlined LCA model results have reasonable alignment with the external modeling team and harmonization results.

4. Contribution Analysis

In LCA, contribution analysis is a method that can identify the key issues of a product system, here completed for characterized impacts from CO_2 and CH_4 or key emissions sources (unit processes) for the life cycle GHG emissions estimated from the model using GWP100 (Figure 4-16a-b). This study primarily reviews CO_2 and methane emissions as part of the GHGs. The study acknowledges other GHG emissions occur along the natural gas supply chain but based on literature analysis, these are deemed immaterial.

The ratios of CO_2:CH_4 for each gate are presented in Figure 4-16a (100 year) and Figure 4-16b (20 year). Appendix E-10 provides a brief discussion around the methane intensity KMIs employed in this study and finds the methane intensities used as KMIs in the model falls well within the ranges reported by other studies.[104, 105, 106]

For both the production through transmission (Gate 1) and production through distribution (Gate 2) boundaries, the production stage is the largest contributor and accounts for about 30% of the GHG intensity on a GWP100 basis. On the production through shipping boundary (Gate 3), the liquefaction and shipping stages become the largest contributor at 43.5% for the Asia case study and 37% for the Europe case study.

Assessing the contribution of methane emissions to the model estimate of total GHGs emissions, methane emissions account for 50% and 54% of total CO_2e emissions on a GWP100 basis for Gates 1 and 2, respectively. Methane contributes less for Gate 3 for both destination case studies (34% and 32%, respectively, for Europe and Asia). For Gate 3, the contribution of CO_2 is greater due to the emissions from liquefaction and LNG shipping (the latter being larger for the LNG delivered to Asia).

Under GWP20, the impact of methane emissions is amplified, contributing 75% and 78% of total CO_2e, respectively, for Gates 1 and 2. Similarly, the methane contributions are 60% and 58% of total GHG emissions, respectively, for the LNG cases to Europe and Asia.

Methane emissions account for significant CO_2e for all gates, with the production stage as the largest contributor, followed by transmission,

104 Alvarez, R.A., Zavala-Araiza, D., Lyon, D.R., Allen, D.T., Barkley, Z.R., Brandt, A.R., Davis, K.J., et al. 2018. "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain." Science 361 (6398): eaar7204. https://doi.org/10.1126/science.aar7204.

105 Balcombe, P., Anderson, K., Speirs, J., Brandon, N., and Hawkes, A. 2016. "The Natural Gas Supply Chain: The Importance of Methane and Carbon Dioxide Emissions." *ACS Sustainable Chemistry & Engineering* 5 (1): 3–20. https://doi.org/10.1021/acssuschemeng.6b00144.

106 Contreras, W., Hardy, C., Tovar, K., Piwetz, A.M., Harris, C.R., Tullos, E.E., Bymaster, A., McMichael, J., and Laurenzi, I.J. 2021. "Life Cycle Greenhouse Gas Emissions of Crude Oil and Natural Gas from the Delaware Basin." *Journal of Cleaner Production*, October, 129530. https://doi.org/10.1016/j.jclepro.2021.129530.

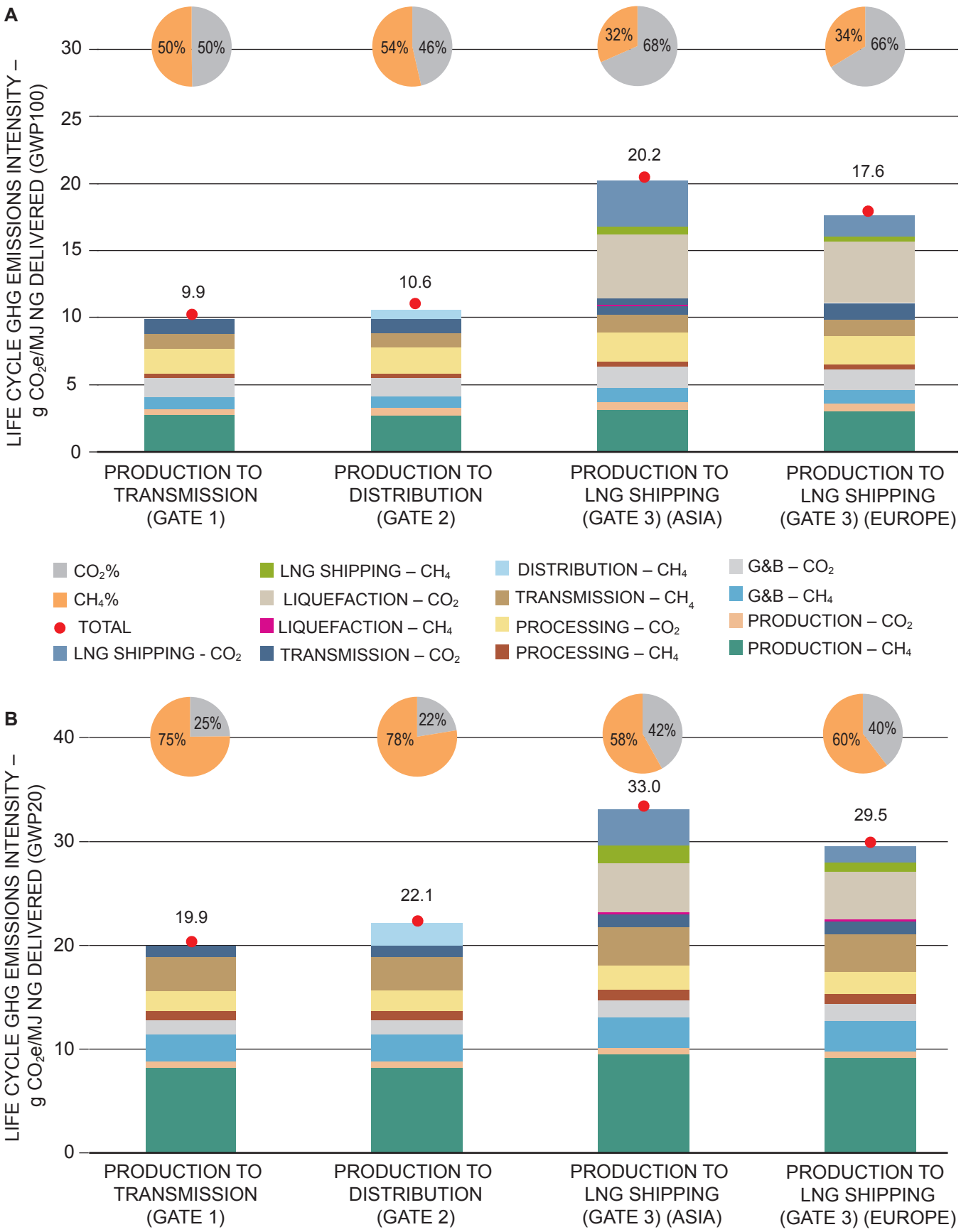


Figure 4-16a–b. *(a) Model Contribution Analysis per Stage and GHG (GWP100) (b) Model Contribution Analysis per Stage and GHG (GWP20)*

gathering and boosting, and shipping segments. This result underscores the need to mitigate emissions across the supply chain. For Gate 3, the relative contribution of CO_2 increases due to the emissions from liquefaction and LNG shipping (the latter being larger for the LNG delivered to Asia). Carbon dioxide remains an important GHG emissions contributor, especially in the liquefaction, processing, shipping, and transmission segments, and therefore targeted mitigation actions, such as carbon capture and storage (CCS), reduced flaring, and electrification of compression combined with low-emissions power may support greater reductions.

a. SLiNG-GHG Model Versus External Modeling Teams—Comparison of Contribution Analysis

The outputs of the SLiNG-GHG model were compared to external model outputs stage-by-stage to verify the representativeness of the model. Figure 4-17a–d shows in detail the contribution of each stage to the total boundary life cycle estimate. As some stages have been defined differently in these models, the bars corresponding to those stages of the models and the comparable equivalents of other models have been hatched (meaning they have been shaded with a pattern).

For both the production through transmission (Gate 1) and production through distribution (Gate 2) boundaries, the SLiNG-GHG model results indicate the production stage is the largest contributor and accounts for about 30% of the U.S. well-to-gate GHG emissions intensity, although this conclusion may not extend to all U.S. natural gas resources. On the production through shipping boundary (Gate 3), the model indicates the liquefaction and shipping stages become the largest contributor, at 44% for the Asia case study and 37% for the Europe case study. In the case of a GWP20 basis, the production stage consistently remains the largest contributor across all three gates ranging from 30%–44%. It must be noted that for the Europe case, liquefaction and shipping put together also contribute 30% to the total emissions.

These results in Figure 4-17a–d also allow comparisons between SLiNG-GHG and external modeling team results. In most instances, the results from SLiNG fall within the ranges of results provided by the external modeling teams. The only exceptions are for CH_4 emissions (Figure 4-17c). For Gate 1, SLiNG has higher CH_4 emissions than all external modeling teams. For Gate 2, SLiNG and Modeling Team 2 are on the upper bound of CH_4 emissions. The relatively high CH_4 emissions from SLiNG are from its production stage.

b. Pathways Analysis

The SLiNG-GHG model was used to assess the well-to-gate intensity of U.S. natural gas and LNG supply chains under four future emissions reduction pathways defined by the NPC in this study. Values of the KMIs for these pathways were estimated by the LCA researchers and industry subject matter experts in the NPC study.

The goal of this assessment is to estimate the potential contribution of GHG emissions reductions across the natural gas supply chain toward the U.S. 2030 and 2050 GHG emissions reduction targets and Global Methane Pledge. The following provides life cycle GHG emissions estimates for the U.S. natural gas supply chain under three pathways: Existing Policies (EP), Continued Reductions (CR), and Technology, Innovation, and Policy (TIP). For more detail on the assumptions for these pathways, see Chapter 1. Appendix E-11 details the specific input KMI values used to estimate the life cycle GHG emissions intensity under these different pathways.

Figure 4-18a and b and Table 4-2 list the model results for the NPC-defined pathways.

Employing the SLiNG-GHG, the study finds that, relative to the national average Reference case, the life cycle GHG emissions intensities (g CO_2e/MJ natural gas delivered) are estimated to be reduced by approximately 38%–39% on a GWP100 basis and 52%–55% on a GWP20 basis for the domestic natural gas supply chain (production through distribution) in 2030. Under the LNG export cases, relative to the Reference case, the GHG emissions intensities are estimated to be lower by approximately 22%–25% and 39%–42% on a GWP100 and GWP20 basis, respectively. The reduction potential grows to 38%–54% on a

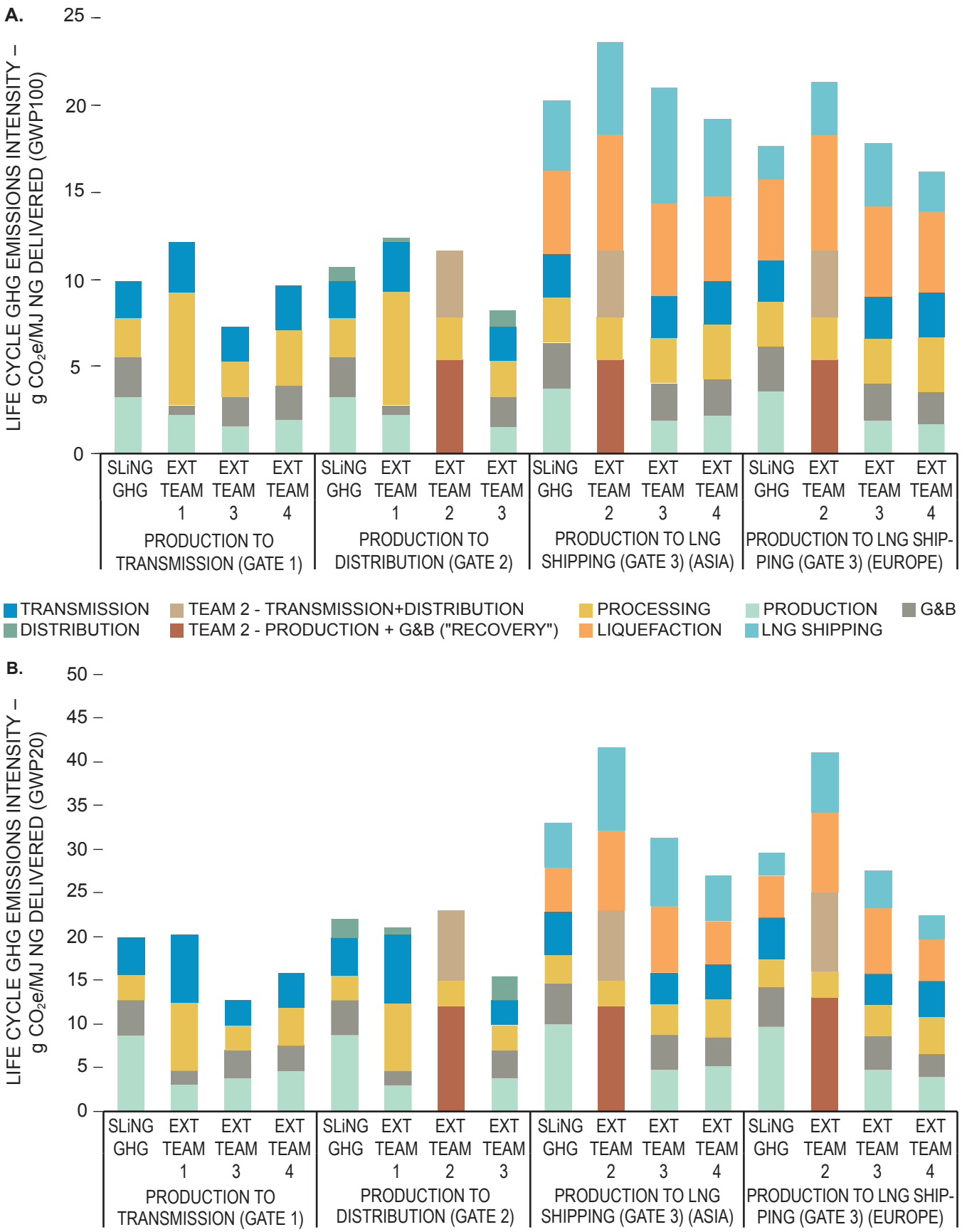


Figure 4-17a–b. *Comparative Contribution Analysis of SLiNG-GHG Model and External Model Stagewise Outputs for: (a) Life Cycle CO_2e Emissions (GWP100), (b) Life Cycle CO_2e Emissions (GWP20)*

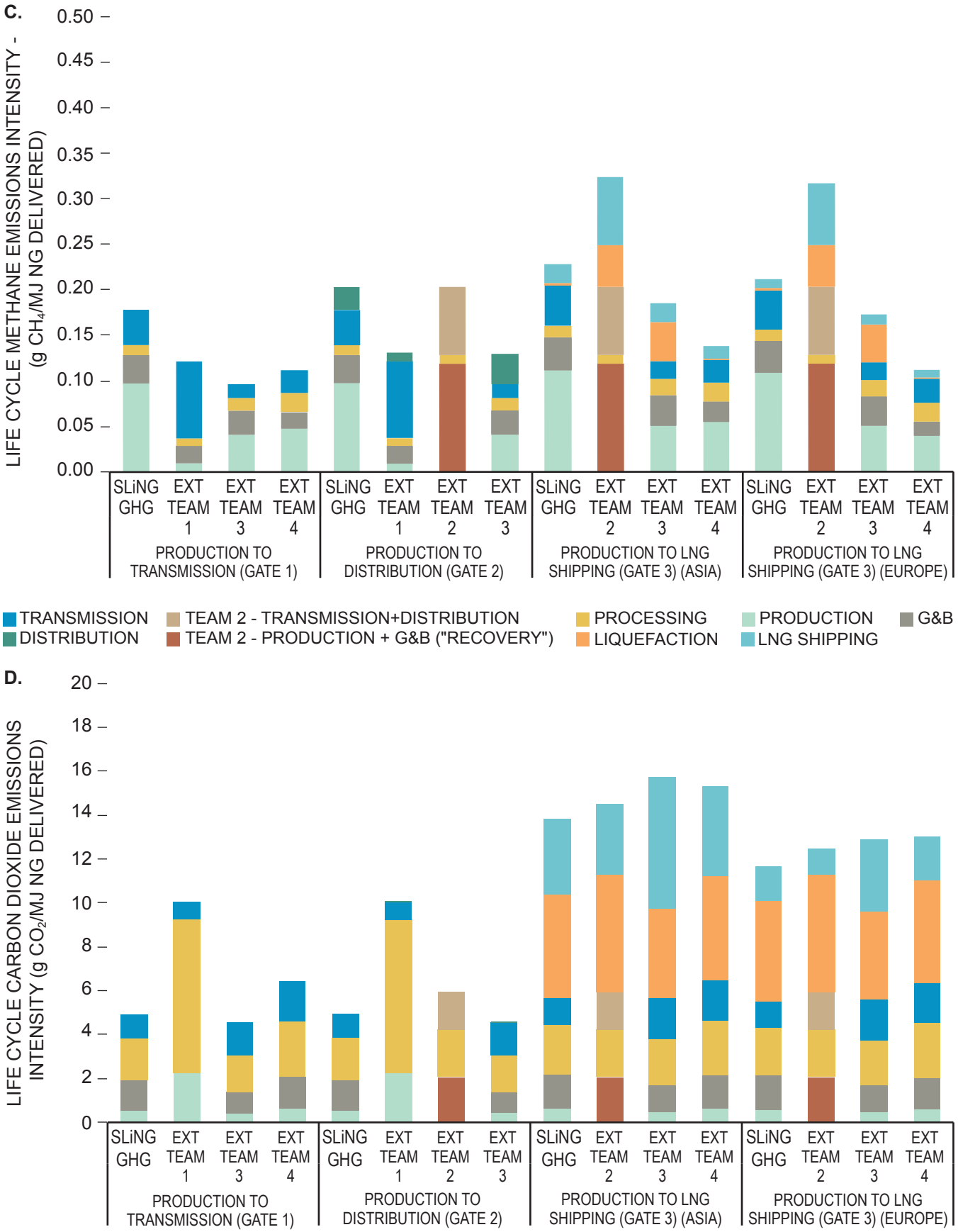


Figure 4-17c–d. *Comparative Contribution Analysis of SLiNG-GHG Model and External Model Stagewise Outputs for: (c) Life Cycle CH_4 Emissions, (d) Life Cycle CO_2 Emissions*

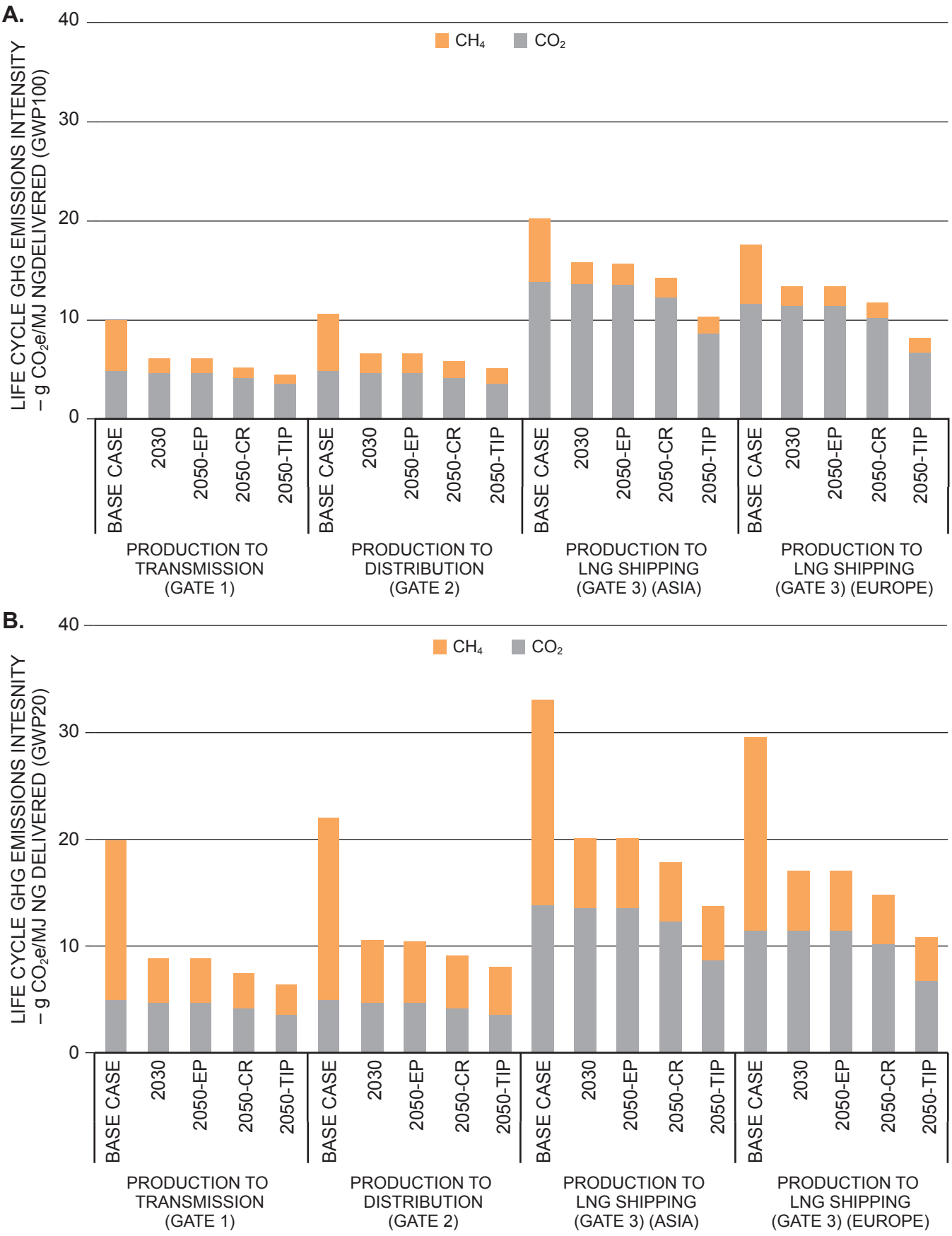


Figure 4-18a–b. *SLiNG-GHG Model Results for Various NPC-Defined Pathways for All System Gates Considered (a) GWP100 (b) GWP20*

Gate metric: g/MJ NG delivered		2030	2050-EP	2050-CR	2050-TIP
Gate 1	CO_2	5%	5%	17%	28%
	CH_4	72%	72%	78%	81%
	GWP100	39%	39%	48%	54%
	GWP20	55%	55%	63%	68%
Gate 2	CO_2	5%	5%	17%	28%
	CH_4	66%	66%	71%	74%
	GWP100	38%	38%	46%	52%
	GWP20	52%	52%	59%	63%
Gate 3 (Asia)	CO_2	2%	2%	11%	37%
	CH_4	66%	66%	71%	74%
	GWP100	22%	22%	30%	49%
	GWP20	39%	39%	46%	59%
Gate 3 (Europe)	CO_2	2%	2%	12%	43%
	CH_4	69%	69%	74%	78%
	GWP100	25%	25%	33%	54%
	GWP20	42%	42%	50%	64%

Note: Future pathway percent emissions reduction is relative to the 2020 Reference case.

Table 4-2. *SLiNG-GHG Model Results for Various Pathways*

GWP100 basis for domestic scenarios and 22%–54% for LNG export cases under the various 2050 scenarios.

This analysis reveals more than 66%–72% reduction in methane emissions intensities across all boundaries and pathways with modest reductions (2%–5%) in carbon dioxide emissions intensities by 2030. Under the higher future emissions reduction pathways, methane emissions intensity reductions of about 74%–81% by 2050 (TIP scenario) are estimated across all boundaries with 28% reductions in CO_2 emissions intensities by 2050 (TIP scenario) for domestic natural gas supply chains and 37%–43% CO_2 emissions intensity reductions in the LNG supply chains considered in this study. More than 90% of the emissions reductions modeled in 2030 are attributed to methane emissions reductions from existing or proposed regulations across the supply chain for both the domestic and LNG supply chains. In the 2050 (TIP) scenario, methane emissions reductions continue to play a significant role in GHG emissions reduction, along with electrification of some G&B facilities and transmission compressor stations, as well as CCS at LNG liquefaction plants.

c. *Supply Chain Analysis*

Recent multiscale measurement campaigns across the United States have identified spatial and temporal variations in methane emissions from the oil and gas supply chain. Furthermore, resource characteristics, operational practices, and the regulatory environment vary across the United States, resulting in significant differences in methane emissions by operator, state, and basin. Statutory and regulatory drivers such as the Inflation Reduction Act and voluntary initiatives, including differentiating gas or LNG supply chains based on their GHG emissions and other environmental attributes, increasingly require GHG emissions assessment at the subnational, regional, operator, and supply chain-specific scales. For example, the methane waste emissions charge in the Inflation Reduction Act requires that fee liabilities are calculated using operator-specific and empirical estimates of methane emissions intensity. Operationalizing a global differentiated natural gas framework through a common measurement, monitoring, reporting, and verification (MMRV) program requires the ability to verifiably distinguish emissions across

ALLOCATION OF GHG EMISSIONS AMONG OIL, NATURAL GAS, AND NGL PRODUCTS IN OIL AND GAS PRODUCTION BASINS

Methods used for emissions aggregation and allocation have significant impacts on life cycle GHG emissions estimates for oil and gas products; however, because of limited data availability for upstream and midstream oil and gas operations, the influence of the allocation technique has not been extensively explored. In the most detailed analysis available, Chen et al., (2019)[1] examined GHG emissions associated with oil and gas production and processing in the Eagle Ford Shale oil and gas production region, which contains dry gas, wet gas, and associated gas production regions.

Chen et al., (2019) estimated emissions of GHGs for each of the more than 10,000 sites in the basin, then allocated emissions among oil, natural gas, and NGL products in multiple ways. These included:

- Allocating emissions basinwide based on the energy content of oil, natural gas, and NGLs produced basinwide
- Allocating emissions in 12 subbasins, based on the energy content of oil, natural gas, and NGLs produced in each subbasin; subbasin domains were defined based on the gas-to-oil ratio.
- Process-level allocations where emissions were allocated based on the products associated with the process. For example, oil tank emissions would be assigned to oil tanks in this system.

The results demonstrate that there can be relatively large differences in allocations between a process/equipment-level allocation, especially in wet gas regions where there are substantial volumes of both gas and liquid products. Co-allocating products is a vital step in development of LCAs to ensure the GHG burdens are attributed correctly between the different products produced.

1 Chen, Q., Dunn, J.B., and Allen, D.T. 2019. "Aggregation and Allocation of Greenhouse Gas Emissions in Oil and Gas Production: Implications for Life-Cycle Greenhouse Gas Burdens." *ACS Sustainable Chemistry & Engineering* 7 (20): 17065–73. https://doi.org/10.1021/acssuschemeng.9b03136).

different global natural gas supply chains. Limited studies of supply chain-specific life cycle GHG emissions show material differences in emissions intensities relative to nationally representative models.[107] To support these developments in policy and ensure U.S. leadership in global carbon accounting initiatives, geospatial LCA tools that make use of advancements in technology development and availability of data worldwide is necessary.

Most publicly available GHG LCA models have been parameterized at the national level, with model input values identified to be representative of overall U.S. oil and gas operations. These models represented the best-in-time analysis of the GHG emissions of U.S. natural gas supply chains, when reliable and large-scale data on methane emissions were not available. Furthermore, past policies and voluntary initiatives did not require subnational or supply chain-specific differentiation, likely in part due to some of these tools just beginning to emerge.

The SLiNG-GHG model was used to assess the impact of specific supply chains[108] for both domestic and LNG supply chains under the Reference case. Descriptions of the supply chains and their representativeness are discussed in Chapter 5. Appendix E-11 documents the exact KMI values modeled to represent these supply chains. The U.S. Reference case set of input parameters

107 Roman-White, S.A., Littlefield, J.A., Fleury, K.G., Allen, D.T., Balcombe, P., Konschnik, K.E., Ewing, J., Ross, G.B., and George, F. 2021. "LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting." *ACS Sustainable Chemistry & Engineering* 9 (32): 10857–67. https://doi.org/10.1021/acssuschemeng.1c03307.

108 The goal of this analysis was to estimate the GHG emissions intensities of these study-selected supply chains; however, limited data were available to inform many of the KMIs for these specific regions. For multiple KMIs, proxy data was employed using best-available data based on subject matter input. The set of assumptions and data proxies (along with all sources) are documented in Appendix E-12.

was used as the starting point, and then adjusted for each supply chain where data was available to regionalize. The EPA GHGRP, EIA, and published literature were key data sources for this modeling. Results are shown in Figure 4-19a–b.

5. Incorporating Measurements in LCAs

Over the past decade, there has been significant progress in the development of new technologies to detect, monitor, measure, and quantify methane emissions from oil and gas facilities at multiple scales. Top-down estimates, such as those derived using aerial-based or satellite measurement data, have been extensively deployed in major U.S. basins.

These measurements have revealed several key features of U.S. oil and gas methane emissions. First, methane emissions exhibit a skewed distribution—a small number of high-emitting sources are responsible for a large fraction of total emissions.[109, 110] Second, high-volume, intermittent emissions events have been identified as being a significant contributor to total emissions—accurate accounting for such events requires frequent or large-scale monitoring.[111] Third, inventory estimates both at the federal (e.g., EPA GHGI) and state level underestimate emissions compared to measurements.[112 113] This can be attributed to several factors, including outdated activity data, emissions factors that are not representative of the skewed emissions distributions, missing source categories, and lack of formal mechanisms to incorporate large volume, but intermittent emissions events in emissions inventories.[114, 115] Fourth, common LCA frameworks or models do not fully incorporate top-down measurement-informed emissions datasets and estimates, such as those estimated through aerial surveys or satellites to develop LCIs, due to limitations in the reported measurement data, and thereby may introduce an underestimation bias in life cycle emissions intensities.[116, 117]

Thus, widespread incorporation of measurement-informed emissions inventories within an LCA framework may be beneficial to represent the emissions intensity of U.S. natural gas and LNG supply chains. This could also further assist with incorporating measurements and empirical data in official reporting requirements. For example, the EPA has proposed updated reporting requirements for U.S. oil and gas operators that places greater emphasis on using empirical and measurement data to accurately reflect methane emissions in its inventories. Finally, as measurements expand globally through efforts such as DOE's MMRV, it will be necessary to have common, direct measurement-informed LCA frameworks as a starting point to consistently compared GHG emissions impacts across global supply chains.[118]

109 Brandt, A.R., Heath, G.A., and Cooley, D. 2016. "Methane Leaks from Natural Gas Systems Follow Extreme Distributions." *Environmental Science & Technology* 50 (22): 12512–20. https://doi.org/10.1021/acs.est.6b04303.

110 Lauvaux, T., Giron, C., Mazzolini, M., d'Aspremont, A., Duren, R., Cusworth, D., Shindell, D., and Ciais, P. 2022. "Global Assessment of Oil and Gas Methane Ultra-Emitters." *Science* 375 (6580): 557–61. https://doi.org/10.1126/science.abj4351.

111 Cusworth, D.H., Duren, R.M., Thorpe, A.K., Olson-Duvall, W., Heckler, J., Chapman, J.W., Eastwood, M.L., et al. 2021. "Intermittency of Large Methane Emitters in the Permian Basin." *Environmental Science & Technology Letters* 8 (7): 567–73. https://doi.org/10.1021/acs.estlett.1c00173.

112 Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P., Heath, G.A., Englander, J., Cooley, D., Lyon, D., et al. 2021. "Closing the Methane Gap in U.S. Oil and Natural Gas Production Emissions Inventories." *Nature Communications* 12 (1). https://doi.org/10.1038/s41467-021-25017-4.

113 Alvarez, R.A., Zavala-Araiza, D., Lyon, D.R., Allen, D.T., Barkley, Z.R., Brandt, A.R., Davis, K.J., et al. 2018. "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain." *Science* 361 (6398): eaar7204. https://doi.org/10.1126/science.aar7204.

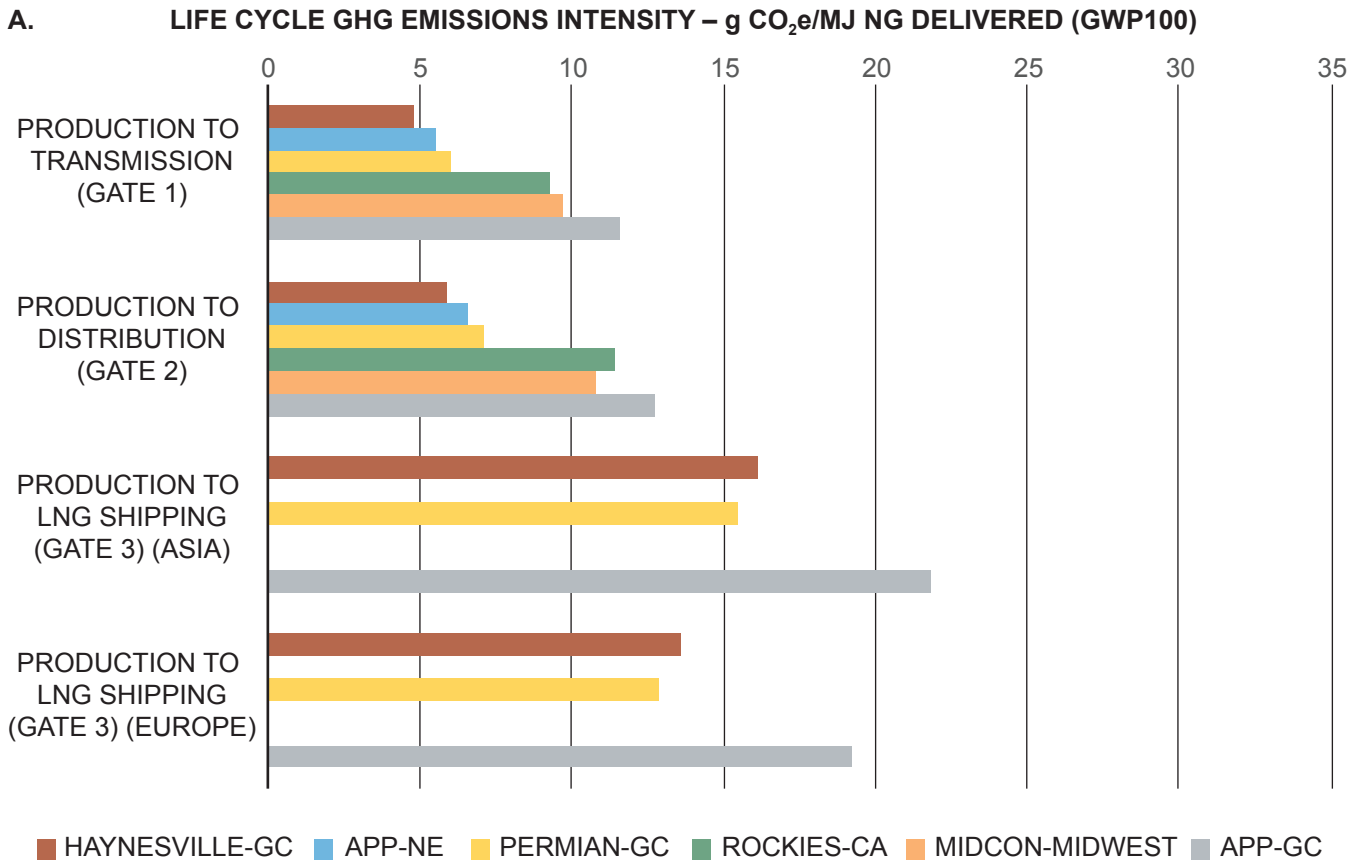
114 Allen, D.T., Ravikumar, A., and Tullos, E. 2023. "Scientific Challenges of Monitoring, Measuring, Reporting, and Verifying Greenhouse Gas Emissions from Natural Gas Systems." *ACS Sustainable Resource Management* 1 (1): 10–12. https://doi.org/10.1021/acssusresmgt.3c00132.

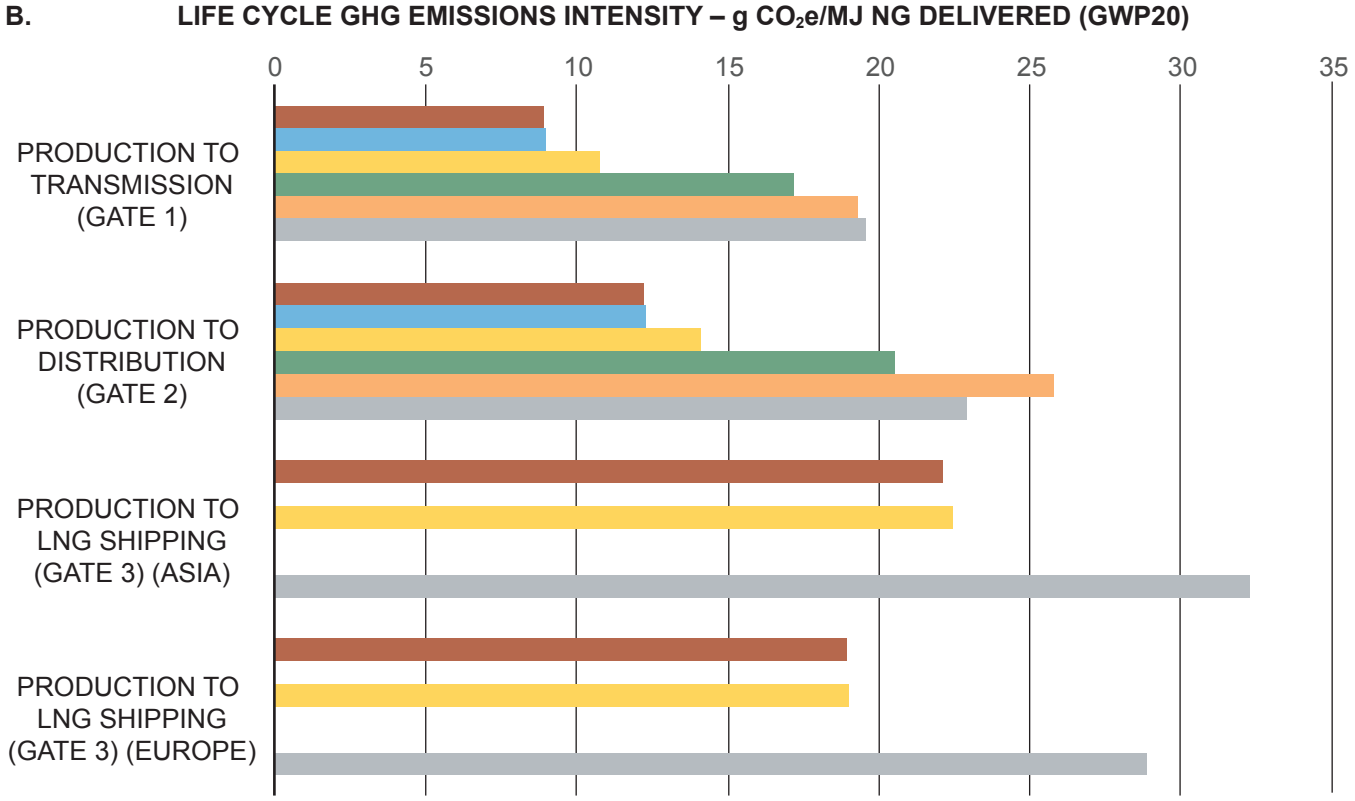
115 Liu, R.E., Ravikumar, A.P., Bi, X.T., Zhang, S., Nie, Y., Brandt, A., and Bergerson, J.A. 2021. "Greenhouse Gas Emissions of Western Canadian Natural Gas: Proposed Emissions Tracking for Life Cycle Modeling." *Environmental Science & Technology* 55 (14): 9711–20. https://doi.org/10.1021/acs.est.0c06353.

116 Irakulis-Loitxate, I., Guanter, L., Liu, Y-L., Varon, D.J., Maasakkers, J.D., Zhang, Y., Chulakadabba, A., et al. 2021. "Satellite-Based Survey of Extreme Methane Emissions in the Permian Basin." Science Advances 7 (27). https://doi.org/10.1126/sciadv.abf4507.

117 Varon, D.J., Jacob, D.J., Hmiel, B., Gautam, R., Lyon, D.R., Omara, M., Sulprizio, M., et al. 2023. "Continuous Weekly Monitoring of Methane Emissions from the Permian Basin by Inversion of TROPOMI Satellite Observations." *Atmospheric Chemistry and Physics* 23 (13): 7503–20. https://doi.org/10.5194/acp-23-7503-2023.

118 Ravikumar, A.P., Tullos, E.E., Allen, D.T., Cahill, B., Hamburg, S.P., Zimmerle, D., Fox, T.A., et al. 2023. "Measurement-Based Differentiation of Low-Emission Global Natural Gas Supply Chains." *Nature Energy* 8 (11): 1174–76. https://doi.org/10.1038/s41560-023-01381-x.





Note: Only the Gulf Coast supply chains were estimated on the production through shipping boundary, as the majority of U.S. LNG is exported from the Gulf Coast.

Figure 4-19a–b. *Model Results for Different Supply Chains and Boundary Scenarios (a) GWP100 (b) GWP20*

a. Key Technical Challenges

Key challenges in integrating GHG emissions measurement data with conventional LCA models are described in the following sections.

i. Spatial and temporal boundary matching

The spatial and temporal resolution of methane emissions measurement technologies vary significantly. While aerial- and drone-based technologies can detect emissions at the scale of equipment (~10s of meters), satellites aggregate emissions over a larger area (~100s of meters to several kilometers). Different scales of measurements aggregate emissions from different sources and process stages. For example, publicly available data from existing satellites such as TROPOMI provide methane emissions estimates at a spatial resolution of about 7 km^2, which can encompass multiple stages of the supply chain, including drilling and completion, production, G&B, and processing. For such data to be used in the context of a LCI would require disaggregation of observations across different process and supply stages. Even for technologies that provide higher spatial resolution, such as aerial surveys that routinely detect emissions at individual equipment and facility scales, disaggregation across process stages can be challenging. In associated gas basins such as the Permian, emissions detected over an oil and gas production facility must be allocated to different product streams, including crude oil, NGLs, and dry natural gas. Depending on the allocation method, additional metadata such as emissions source would be necessary for appropriate emissions disaggregation.

Similarly, survey-type solutions often collect snapshot emissions information that, by definition, cannot accurately represent the intermittent nature of emissions without additional analyses or surveys. Incorporation of measurements within a LCI requires that snapshot measurements are appropriately scaled to represent annual (or other time-averaged), measurement-informed inventories.

ii. Supporting emissions allocation

In an LCA, emissions are allocated to different product streams. Although energy-based allocation methods have been common in the context of natural gas supply chains, other approaches, such as process-based or value-based allocation, have been used in the literature. Irrespective of the method of allocation, a consistent method to allocate emissions across crude oil, NGLs, and dry gas is required for consistent global comparisons of life cycle emissions intensities. Allocating observed emissions to different product streams requires knowledge of production volumes and resource composition at the time of measurement. Furthermore, allocation must be conducted in different stages based on the reporting requirements of individual jurisdictions. In the United States, only crude oil and produced gas volumes are reported at the lease level (production facility) in associated gas basins while NGLs and dry gas volumes are reported at the outlet of the processing facility. Depending on the actual location of these basins, liquids that are produced in one state may be reported from a processing facility that is in a different state. For measurements to be useful in the context of developing process stage-level LCI, reporting standards must be established that would require measurement campaigns to report disaggregated production volumes in addition to emissions data.

iii. Verifying upstream emissions intensity

LCA studies are normalized to unit volumes of delivered product as they enable direct comparisons across different supply chains. This requires LCIs across different process stages to be normalized to production or throughput at that stage. Because most field campaigns report snapshot measurement data that are often remotely collected and can often span multiple operators' facilities, the corresponding production or throughput data at the time of measurement are not readily available. Using publicly available monthly or annual production data is not a viable approach given the large variation in observed methane emissions. Thus, reporting standards must be established to enable use of measurement data to develop LCIs.

iv. Consistent treatment of below-detection threshold emissions

Peer-reviewed studies and field campaigns have demonstrated a wide range in the detection

threshold of technologies. While some drone- and aerial-based methane emissions surveys can detect emissions in the 1 kg/hr–5 kg/hr range, satellites can only detect emissions that are 100 kg/hr or higher. Research groups have adopted several approaches to estimate emissions below the detection threshold of the measurement instrument that are not harmonized. This creates emissions estimates in different studies that are not directly comparable. To enable use of measurement-informed inventories in LCAs, reporting standards should include standardized approaches to estimate below-detection threshold emissions.

v. Representing intermittent events

A large body of research has identified the contribution of short-duration intermittent emissions events to total emissions. Whether a measurement campaign detects and quantifies a representative distribution of intermittent emissions events depends on several factors, including survey frequency, detection threshold, and the duration of the emissions event. Multiple approaches have been developed in the literature to account for intermittency, including repeated sampling of a group of facilities, modeling frequency and duration of intermittent emissions events with data from continuous monitoring sensors, large spatial sampling to capture representative samples of intermittent events, and using operational data to supplement observations. While all methods are valid under appropriate assumptions and measurement scenarios, a consistent approach to treating intermittent emissions events is necessary to integrate data from multiple measurement campaigns.

b. Uncertainty Quantification in Measurement-Informed LCAs

Measurement-informed LCAs bridge multiscale, multimodal measurements of methane emissions and associated uncertainty with the uncertainty of system modeling and assumptions in the LCA. Developing systems-level uncertainty estimates for GHG emissions intensity of supply chains associated with measurement-informed LCAs requires advances in uncertainty quantification across two domains. These two domains include measurement system uncertainty and LCA uncertainty, and methods to quantify uncertainty in these domains must be developed independently and integrated in the context of measurement-informed LCIs. Based on the framework described in Figure 4-20, the measurement system uncertainty is best suited to be developed by those involved in methane measurement science, modelers, statisticians, and others, concurrent with the field campaigns while the LCA uncertainty is best suited to be developed by the LCA practitioner community.

i. Measurement system uncertainty

Several aspects of uncertainty must be considered to derive an overall confidence internal for measured emissions estimates. These include:

- **Uncertainties in atmospheric measurements:** Measurement uncertainties are associated with the sensor or instrument and are effectively characterized through laboratory and field testing and reduced through standardized calibration procedures. For mature laser-based instruments, these concentration measurement uncertainties are generally low compared to other sources of uncertainty.

- **Uncertainties in estimating of emissions rates:** All technologies that measure atmospheric concentrations or concentration path lengths will use dispersion modeling to convert sensor signals to emissions-rate estimates. Uncertainties in calculating an emissions rate can be significant depending on the type of sensor, the complexity of the facility or system under measurement, correct attribution to the source, and local atmospheric conditions. These uncertainties also affect a technology's source attribution capability. Evaluating uncertainty in emissions-rate estimation can be done through blind controlled release testing of technologies to evaluate quantification and estimation errors. However, the diversity in oil and gas infrastructure and associated variation in atmospheric, operational, and geographic conditions requires that such blind testing may need to be conducted across a range of testing conditions.

- **Uncertainties in extrapolation:** Most measurement studies are conducted across a

representative number of facilities or a subregion in an oil and gas basin and are based on short-duration measurements. Reporting emissions rates for the entire basin therefore requires spatial and temporal extrapolation from the sample to the larger population of sites in the basin. Reporting annual emissions estimates for the basin further requires temporal extrapolation. Spatial extrapolation should consider the representativeness of the facilities in the measurement sample and the impact of intra-basin differences in resource properties (e.g., changing gas-to-oil ratio). Temporal extrapolation requires a detailed characterization of the frequency and duration of emissions events throughout the year. Quantitative uncertainty estimation for spatial and temporal extrapolation are in early stages of development and more robust methods are required.

In addition to the uncertainties above, the detection threshold of individual technologies introduces uncertainty in overall emissions estimates. Harmonized methods to estimate emissions that are below the detection threshold of the measurement instrument should be developed. Multimodal measurements with varied detection thresholds that can cross validate are necessary to reduce uncertainty.

ii. LCA uncertainty

Uncertainty is introduced in the measurement-informed LCA in several stages as described in the next few paragraphs. While some of these uncertainties can be reduced through careful methodological development, others are more appropriately analyzed through scenario analysis with a range of assumptions about key parameters.

- **Allocation uncertainty:** LCA studies of natural gas supply chains typically undertake an energy-based allocation approach, where emissions are apportioned to various products such as crude oil, NGLs, and dry natural gas. While this allocation is conducted at the unit process level in LCA modeling, many top-down measurements do not have high spatial resolution to unit process-level allocation. Thus, energy-based allocation for top-down measurement data is calculated at the aggregate level of the supply chain, assuming that the ratio of different coproducts is uniform across the region or the supply chain. However, recent evidence suggests that there are significant intrabasin differences in volume of coproducts that an energy-based allocation should consider production volumes of only those facilities for which methane measurements are available and cannot be extrapolated to other facilities.[119] A long-term solution to reduce this uncertainty may involve improving the spatial resolution of reporting production volumes. Current reporting requirements in the United States allows for crude oil volumes to be reported at the lease (facility) level while NGLs are reported as the outputs of processing plants, which aggregate liquids from multiple facilities across different states. More granular reporting requirements would enable accurate allocation of emissions to different coproducts.
- **Boundary matching uncertainty:** The spatial resolution of measurement technologies varies significantly from a few meters (equipment-level) for aerial surveys to a few kilometers for satellite-based surveys. These boundaries do not typically align with LCA boundaries for specific products and result in uncertainty based on the degree of matching that can be achieved. Technologies with low spatial resolution may aggregate emissions from a large number of facilities on the ground—using such measurement data to develop LCIs for specific products requires making assumptions about allocating total measured emissions to different life cycle products and stages. Uncertainties are introduced when activity data associated with low spatial resolutions methane emissions measurements are not available. The complexity of matching the spatial scale of measurement data with higher resolution activity data could result in accounting overlaps or gaps in LCI. New frameworks to reduce uncertainties associated with boundary matching data across different spatial scales are needed.

119 Allen, D.T., Chen, Q., and Dunn, J.B. 2021. "Consistent Metrics Needed for Quantifying Methane Emissions from Upstream Oil and Gas Operations." *Environmental Science and Technology Letters* 8 (4): 345–49. https://doi.org/10.1021/acs.estlett.0c00907.

c. *Framework for Incorporating Measurements Within LCAs*

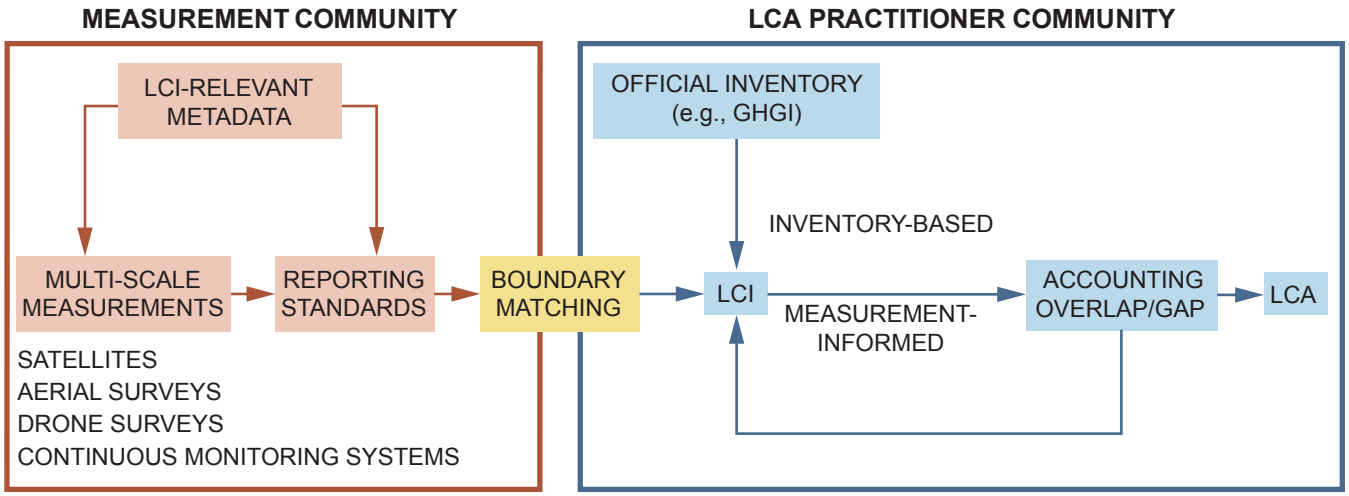
Figure 4-20 shows a framework for incorporating measurement data in the context of LCAs of natural gas supply chains. The key enabling idea is to bring together the measurement community that undertakes multiscale field campaigns to directly measure GHG emissions across the U.S. oil and gas supply chain with the LCA practitioner community that assembles detailed, process-specific LCIs for use in LCAs.

i. Reporting standards

Rapid expansion in the use of multiscale measurement systems to improve accuracy of GHG emissions estimates can enable measurement-informed LCAs of global natural gas supply chains. Based on the challenges described above, a publicly available reporting standard that specifies minimum requirements for emissions data reporting is necessary to ensure that the measurement community includes information needed to construct LCIs. This might be accomplished through a multistakeholder measurement and LCA advisory group that includes experts from the DOE and EPA, plus LCA practitioners from national laboratories and academic institutions, oil and gas operators, and measurement experts from the industry, academia, NGOs, and other stakeholders. The goal of the advisory group could be to develop consensus approaches and methodological guidelines to report methane emissions intensities at appropriate spatial scales, metadata necessary to develop measurement-informed LCIs (e.g., production or throughput volumes), emissions allocation methods, methods to treat intermittency, and recommendations on integrating data from multiple technologies. The recommendations of the advisory group can be revised periodically as technologies advance or new analysis approaches are developed.

ii. Boundary matching

Measurement system boundaries and spatial resolution vary based on technology used to measure GHG emissions, and do not necessarily align with those of LCIs. For example, satellite data routinely have high temporal resolution, providing weekly emissions estimates, but have low spatial resolution, aggregating emissions from facilities across several kilometers. Thus, using satellite-derived emissions data, in the context of LCIs, should reveal the supply chain stages aggregated in such datasets—in this scenario, satellite data may aggregate emissions from production, G&B, and processing stages. Boundary matching is a critical step prior to incorporation of measurement datasets within LCIs. Such matching is necessary to ensure that the spatial scale of measurement-informed emissions estimates correspond to the appropriate life cycle



Note: LCI refers to life cycle inventory that serves as inputs to an LCA model.

Figure 4-20. *Framework for Incorporating Measurements in the Context of LCA of Natural Gas Supply Chains and the Interaction Between the Measurement Community and LCA Practitioner Community*

stage. Methods to match measurement boundaries with life cycle stages should be developed for each measurement approach. Accurate method development here will enable future integration of measurement data directly into conventional LCA approaches.

iii. Life cycle inventory

LCIs form the primary inputs to an LCA. Inventories in many conventional LCA models are based on official estimates such as those derived from the EPA GHGRP or the GHGI, or from private databases such as Ecoinvent, or even proprietary operator data. Inclusion of operational data may significantly reduce several aspects of uncertainty identified as Key Technical Challenges above. These are considered inventory-based data in developing LCIs. Boundary-matched and measurement-informed inventory can be used to replace inventory-based inputs to create measurement-informed LCI estimates. This methodological step should ensure matched spatial and temporal boundaries between inventory-based and measurement estimates.

iv. Accounting overlap/gaps

Measurement-informed LCI estimates for each process stage should be evaluated for potential emissions overlap or gaps. Emissions overlap can occur when measurements aggregate emissions from multiple process stages. For example, while flaring-related emissions are a separate category in a conventional LCI, top-down measurement technologies that measure at the facility (or larger) scale incorporate emissions from flares. Gaps in the posterior LCI can occur when measurements do not adequately capture intermittent or episodic emissions events—these can include maintenance activities or those associated with the drilling and completion stages.

5. Sensitivity Analysis Using Empirical Data in the SLiNG-GHG Model

The NPC LCA model incorporates a subset of the CO_2 emissions sources in each stage, while methane emissions are modeled at a coarser stage level (i.e., individual methane unit processes or emissions sources are not individually modeled) and therefore, by design, can account for all methane emissions sources within each stage of the supply chain, but at an aggregated level. The importance and challenges of incorporating measurement-informed or empirical data inputs into LCA models has been described earlier. The study is not aware of an LCA study that has exclusively employed measurements to account for emissions from each unit process in each stage of the natural gas life cycle from drilling and completion through end use. As noted earlier, the study is aware of limited application of measurement data to GHG emissions unit processes by a limited number of modeling teams for certain stages of the supply chain.

To address the limited incorporation of methane emissions measurement data in LCAs and to investigate the impact of such empirical methane data on LCA GHG emissions intensity in the SLiNG-GHG model, two sensitivity case studies were conducted. The first employed methane emissions data derived from inversions from surface and satellite observations for major oil and gas geographies in the United States.[120] This study was chosen as it provided empirical methane emissions and other datasets for national-level results and multiple production basins that matched the supply chain analysis. This study was not an LCA itself, but between the published data (information on intensities, gas versus oil production, etc.) and discussion with the study authors, the study results were able to be transformed into approximate LCA inputs in the SLiNG-GHG model.[121] The second used data from a measurement-informed LCA study,[122] which undertook the necessary steps to transform measurement data into LCA-compatible input data (e.g., considering energy allocation, supply chain

120 Lu, X., Jacob, D.J., Zhang, Y., Shen, L., Sulprizio, M.P., Maasakkers, J.D., Varon, D.J., et al. 2023. "Observation-Derived 2010-2019 Trends in Methane Emissions and Intensities from US Oil and Gas Fields Tied to Activity Metrics." *Proceedings of the National Academy of Sciences.* 120 (17). https://doi.org/10.1073/pnas.2217900120.

121 2019 datasets were used in the sensitivity analysis. Full data for each year (including 2019) are available at https://github.com/luxiaoatchemsysu/Data-USoilgasCH4.

122 Zhu, Y., Allen, D.T., and Ravikumar, A. "Geospatial Life Cycle Analysis of Greenhouse Gas Emissions from US Liquefied Natural Gas Supply Chains." ChemRxiv. 2024; doi:10.26434/chemrxiv-2024-9v8dw. This content is a preprint and has not been peer-reviewed.

boundaries, product flows). This LCA study synthesized work from several published measurement campaigns in two key regions (Marcellus and Permian) to arrive at average methane emissions intensities for different stages of the supply chain. For this sensitivity analysis, only the Permian dataset was employed to ensure consistency with the vintage considered in the harmonization process as part of this study outlined in Section 5 of this chapter.

a. Sensitivity Analysis

The format of the results of Lu et al., required a three-step data transformation to make the inputs compatible with the SLiNG-GHG model. The published 2019 methane emissions intensities (normalized to gross gas produced, unallocated between gas and oil) were the starting point. First, despite the intra-basin allocation uncertainties, and due to limitations with measurement-informed datasets, to conduct this sensitivity analysis, each methane emissions rate was factored by the study-reported "gas fraction to total oil/gas production [%]",[123] which is a necessary dataset for matching such data into existing frameworks. This effectively allocated the total methane emissions to the portion belonging to gas produced on an energy basis (using best data available).

Second, the Lu et al., study regions were best mapped to the NPC study regions. Permian, Appalachia, Haynesville, and the U.S. Reference case were direct mappings. Rockies is represented as an average of Wyoming and Uinta. Midcon is represented as an average of Anadarko, Fayetteville, and West Arkoma.

Third, the intensities were transformed from a gross gas basis to a marketed gas basis, leveraging data published by EIA. For the Appalachia, Haynesville, and Midcon geographies there was little to no change. For the Permian and Rockies there was a small change (approximately 7% and 4% increase, respectively).

The default input values used in the SLiNG-GHG model (see Appendix E-7) are not based on direct emissions measurements conducted specifically for this study. The national Reference case methane intensity KMIs used in the SLiNG-GHG model are a result of the harmonization process. For the supply chain analysis, the EPA GHGRP was primarily leveraged as a publicly available source with wide data coverage to represent upstream methane emissions in the modeling of these supply chains. The national Reference case was most impacted by this scaling, increasing in intensity by about 11%. The emissions rates and transformations and comparison with the Lu et al., sensitivity and the Reference case are shown in Table 4-3.

Per Lu et al., these methane intensities represent total methane emissions observed in the region. While these regions do not map perfectly to our study supply chains, the study assumes these intensities cover production through transmission and storage methane emissions since these stages of the supply chain exist physically mostly within the major oil and gas regions. To employ in the SLiNG-GHG model under the Lu et al., sensitivity case, the study replaced the default production methane KMI with the methane intensities adjusted to marketed production as shown in the last column of Table 4-3. Further, the study zeroed out the methane KMIs for G&B, processing, and transmission and storage, and left as default the methane KMI values for distribution and liquefaction. All other supply chain KMI value were left as documented in the chapter. These assumptions on boundary mapping for the supply chain introduce additional uncertainty in the LCA inventory, the extent of which cannot be quantified with available data.

i. National-level results

Relative to the Reference case, national results employing default KMIs (listed in Appendix E-7), the Lu et al., sensitivity case LCA GHG emissions intensities were 47% higher at Gate 1 (through transmission) and 44% higher at Gate 2 (through distribution) than the Reference case results on a GWP100-year basis. The GHG LCA emissions intensities under this sensitivity case increase to 70% and 64% for Gates 1 and 2 compared to

123 Lu, X., Jacob, D.J., Zhang, Y., Shen, L., Sulprizio, M.P., Maasakkers, J.D., Varon, D.J., et al. 2023. "Observation-Derived 2010-2019 Trends in Methane Emissions and Intensities from US Oil and Gas Fields Tied to Activity Metrics." *Proceedings of the National Academy of Sciences.* 120 (17). https://doi.org/10.1073/pnas.2217900120. See SI Table S4.

Study Supply Chains	Lu et al. (Sensitivity Analysis, 2019 Data Vintage)				NPC Reference Case
Supply Chains (at Gate 2)	Proxy Region from Lu et al.	Unallocated Methane Intensity (Methane emitted per methane portion of gross gas produced)	Allocated Methane Intensity (Methane emitted per methane portion of gross gas produced)	Market Adjusted & Allocated Methane Intensity (Methane emitted per methane portion of marketed gas production)	Methane Intensity (Methane emitted per methane portion of gas delivered from the Transmission network, Gate 1)
Permian to GC	Permian	2.87%	1.03%	1.11%	0.43%
Appalachian to GC	Marcellus	0.46%	0.45%	0.45%	0.78%
Haynesville to GC	Haynesville	1.38%	1.35%	1.35%	0.41%
Rockies to WC	Average of Uinta, Wyoming	2.82%	2.04%	2.13%	0.99%
Midcon to MW	Average of Anadarko, West Arkoma, Fayetteville	4.01%	3.64%	3.64%	0.71%
Appalachian to NE	Marcellus	0.46%	0.45%	0.45%	0.34%
National	U.S.	2.52%	1.46%	1.62%	0.98%

Note: These methane emissions rates are assumed to cover production, gathering, processing, transmission, and storage emissions.

Table 4-3. *Comparison of Methane KMIs Used in Reference Case and Lu et al., (2019) Sensitivity in the NPC LCA Model for Gate 2*

the Reference case GWP20 GHG intensity LCA results. For the LNG export cases (Gate 3), employing the Lu et al., methane KMIs in the NPC LCA model increase the GHG emissions intensities by about 30% under GWP100 and about 50% under GWP20. The results are presented in Figure 4-21a-b.

ii. Supply chain results

The use of Lu et al., methane emissions intensities KMIs in lieu of the methane emissions intensities employed in the Reference case supply chain intensities generally increased the overall LCA results at various Gate 1 supply chain boundaries, ranging from 20% (Appalachia to Northeast) up to as high as 148% (Midcon to Midwest) on a production through transmission basis, GWP100. However, one supply chain decreased in emissions intensity by 10%, Appalachia to Gulf Coast. This likely is from this supply chain covering a large geographic distance between the production region (Marcellus) and the delivery region (Gulf Coast). This decrease may be due to limitations in the Lu et al., study data to represent the transmission segment of the supply chain. Sensitivity analysis results and comparisons with Reference case results for individual supply chains are presented in Appendix E-13 for both GWP100 and GWP20. Further work is needed to refine such satellite-observation estimations, especially when gas travels large distances to other regions that may have different emissions profiles for midstream infrastructure. Similarly, the Appalachia to Gulf Coast supply chains result in about a 7% decrease relative to the Reference case results for the LNG export cases under GWP100.

Focusing on the Permian Basin sensitivity case, relative to the comparable Reference case boundaries, LCA estimates for the Permian to Gulf Coast supply chain increase significantly on

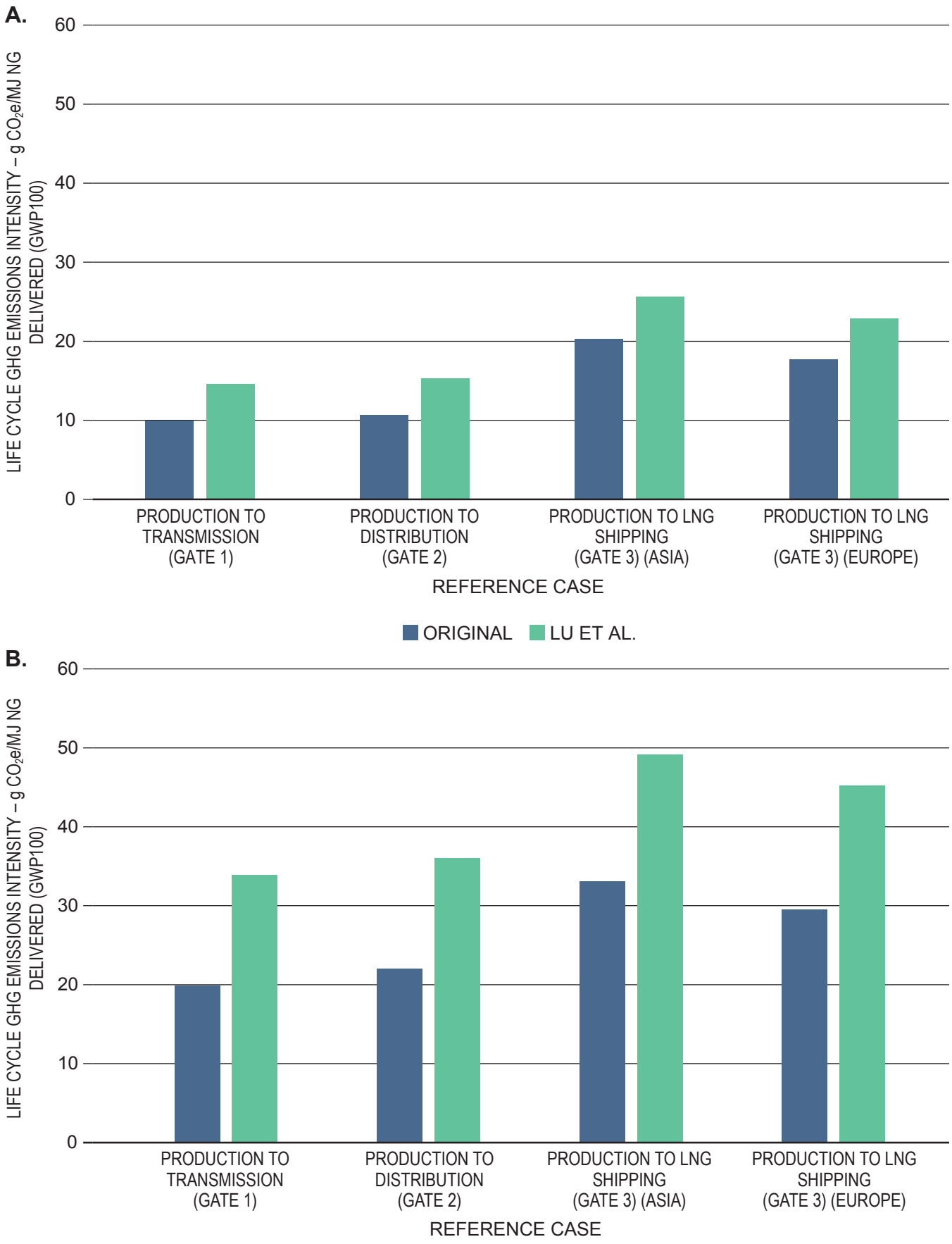


Figure 4-21a–b. *Sensitivity Analysis Using SLiNG-GHG Model (National Averages) (a) GWP100 (b) GWP 20*

Segment	Average Methane Emissions Intensities for Permian Basin (allocated to dry gas production)	
	Reference Case	Zhu et al. (Sensitivity)
Production & G&B	0.13%	1.12%
Processing	0.05%	0.25%

Table 4-4. *Average Methane Emissions Intensities for Permian Basin*

a production through transmission (Gate 1) basis (83%–128% on a GWP100 basis, and 138%–214% on a GWP20 basis), though the impact is lessened when the boundary is extended to LNG delivered to a destination market (37%–76% GWP100 basis across both the European Union and Asia, 58%–118% on a GWP20 basis).

Zhu et al., publishes methane emissions intensities that can be used directly as inputs to the SLiNG-GHG model. Supporting Info Table S28 gives average methane emissions intensities (allocated) for the Permian region, and for, separately, production and G&B (summed together), and processing. The production and G&B methane emissions intensity was input as the production methane KMI value in the SLiNG-GHG model, and thus the G&B methane KMI was zeroed out. The processing methane emissions intensity was input as the processing methane KMI in the SLiNG-GHG model. All other supply chain KMI values were left as documented in the chapter. Table 4-4 compares the methane emissions intensities KMIs used in the Zhu et al., sensitivity case and the Reference case. As noted earlier, the study employs the Permian datasets from this study since it uses pre-2016 datasets to arrive at measurement methane intensities for the Appalachian region.[124]

Full results for all supply chains are included in Appendix E-13. The default methane KMIs employed in the Permian to Gulf Coast supply chain Reference case in the SLiNG-GHG model were compared to two cases[125, 126] developed using empirically derived methane KMIs representative of the Permian to Gulf Coast supply chains (Figure 4-22 a-b) for the three boundaries considered in this study. Results suggest that a replacement

PURPOSE, VALUE, AND LIMITATIONS OF A STREAMLINED LCA MODEL

The purpose of the SLiNG-GHG model is to provide a reasonable, transparent, easy to use, and publicly available screening-level estimate of life cycle GHG emissions for natural gas and LNG supply chains. Existing LCA models have complexities in their application and have seen limited uptake by stakeholders in the public and corporate policymaking. SLiNG-GHG model employs best-available public data sources that are compatible for use in LCA, while balancing timeline and resources. The default values may be customized to users' applications or projects without requiring deep expertise in LCA.

While the model allows users to conduct bespoke evaluation of life cycle GHG emissions, the limitations of such a streamlined model should be recognized and the user may want to consider the use of a more comprehensive LCA model to meet their goals. In SLiNG-GHG, methane and carbon dioxide are handled at different levels of detail. The model incorporates a prioritized subset of the carbon dioxide emissions sources in each stage, intentionally not accounting for typically minor (or not relevant in some regions/supply chains) carbon dioxide emissions sources. Methane is modeled at a coarser stage level and therefore, by design, can account for all methane emissions sources within each stage of the supply chain, but at an aggregated level.

124 Zhu, Y., Allen, D.T., and Ravikumar, A. "Geospatial Life Cycle Analysis of Greenhouse Gas Emissions from US Liquefied Natural Gas Supply Chains." ChemRxiv. 2024; doi:10.26434/chemrxiv-2024-9v8dw. This content is a preprint and has not been peer-reviewed. See Table S27.

125 Lu, Xiao, Daniel J. Jacob, Yuzhong Zhang, Lu Shen, Melissa P. Sulprizio, Joannes D. Maasakkers, D. J. Varon, et al. 2023. "Observation-Derived 2010-2019 Trends in Methane Emissions and Intensities from U.S. Oil and Gas Fields Tied to Activity Metrics" 120 (17). https://doi.org/10.1073/pnas.2217900120.

126 Zhu, Y., Allen, D.T., and Ravikumar, A. "Geospatial Life Cycle Analysis of Greenhouse Gas Emissions from US Liquefied Natural Gas Supply Chains." ChemRxiv. 2024; doi:10.26434/chemrxiv-2024-9v8dw. This content is a preprint and has not been peer-reviewed.

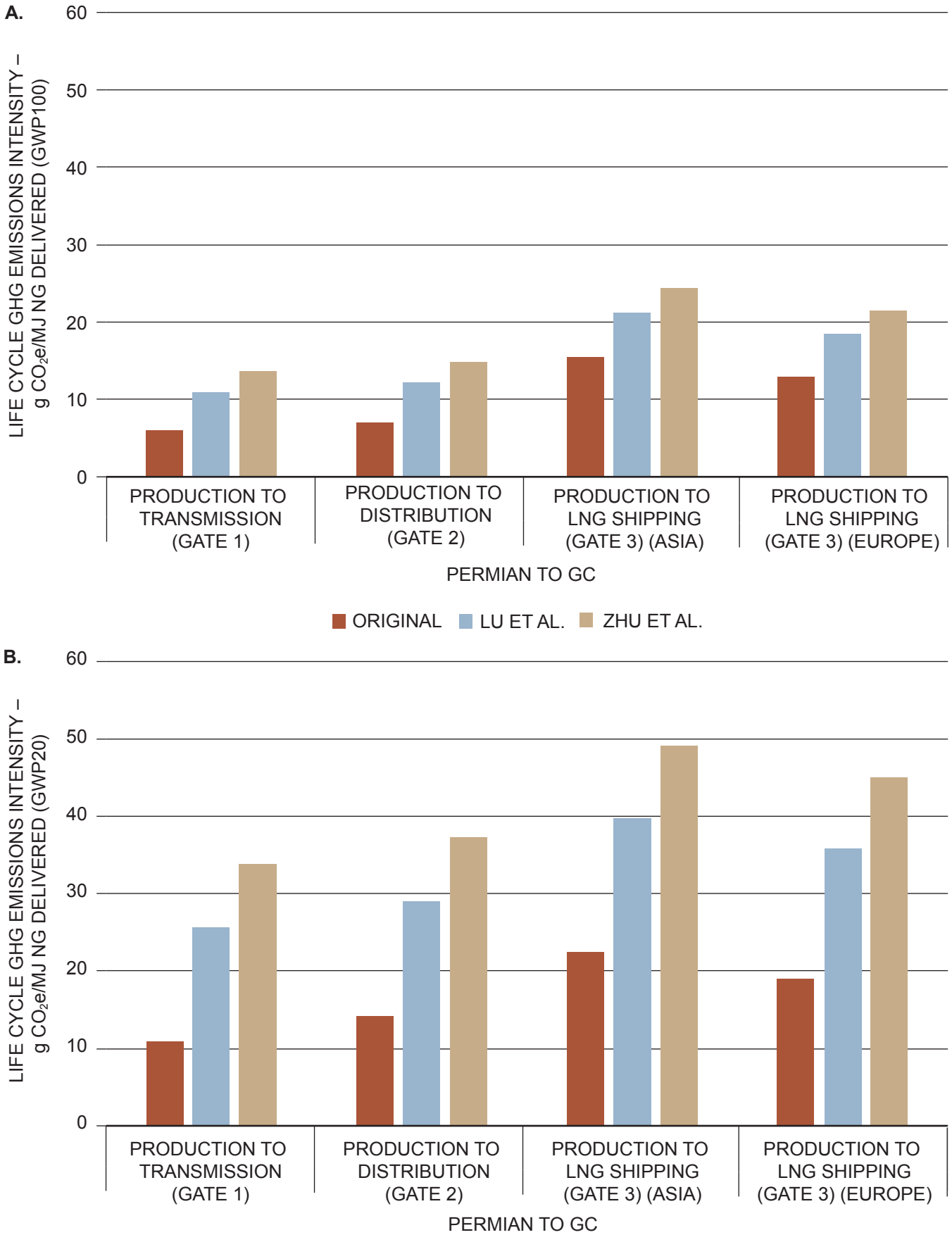


Figure 4-22a–b. *Sensitivity Analysis Using SLiNG-GHG Model (Permian to Gulf Coast Supply Chain) for All System Gates Considered (a) GWP100 (b) GWP20*

of nationally representative default model input data with selected national or regional measurement data could significantly affect understanding of estimated life cycle GHG emissions. As noted previously, national, regional, and basin data may not be representative of all operators in the region.

VI. LCAs IN PUBLIC AND CORPORATE POLICYMAKING

Increased focus on the emissions intensity of traded energy products is creating new demands for life cycle GHG emissions intensity assessments, including certified natural gas schemes from private companies, supply chain-specific corporate LCAs,[127] and transparent frameworks for MMRV[128] for pipeline gas and LNG (driven by the United States, European Union, East Mediterranean Gas Forum, and more than 15 other countries). This section reviews key U.S. and international policies related to use or potential use of LCAs.

A. The Inflation Reduction Act (IRA)

The IRA introduced several new requirements for LCA. The law created new federal requirements for LCA related to newly available tax credits for producing hydrogen, sustainable aviation fuel, and biofuels.

The IRA, in Section 13204, created the Clean Hydrogen Tax Credit with a life cycle GHG emissions requirement of 4 kg CO_2e per kg of hydrogen.[129] The Department of the Treasury is responsible for determining how hydrogen producers can meet the eligibility criteria. LCA studies find that blue hydrogen can be compatible with a lower carbon future.[130]

Section 40001 of the IRA created a grant program led by the Department of Transportation for sustainable aviation fuel and low-emissions aviation technologies.[131] Sustainable aviation fuel is defined as achieving at least a 50% life cycle GHG emissions reduction in comparison with petroleum-based jet fuel. The law states that a fuel's GHG emissions intensity must be defined in accordance with the LCA set by the International Civil Aviation Organization for the Carbon Offsetting and Reduction Scheme for International Aviation or "any similar methodology" that satisfies criteria in the Clean Air Act.

The IRA also extended the biofuel tax credit to the end of 2024.[132] Biodiesel blenders are eligible for a tax credit of $1 per gallon of pure biodiesel, agri-biodiesel, or renewable diesel blended with petroleum diesel to produce a mixture containing at least 0.1% diesel fuel. The blenders must have produced and sold or used the biodiesel as a fuel in their business. The IRA requires the LCA to be based on the GREET (Greenhouse gases, Regulated Emissions, and Energy use in Technologies) model developed by the Argonne National Lab.[133, 134]

B. Renewable Fuel Standard

Established under the Energy Policy Act of 2005, the first Renewable Fuel Standard (RFS) requires refiners to blend biofuels with gasoline at volumes set by the EPA.[135] The Energy

127 Roman-White, S.A., Littlefield, J.A., Fleury, K.G., Allen, D.T., Balcombe, P., Konschnik, K.E., Ewing, J., Ross, G.B., and George, F. 2021. "LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting." *ACS Sustainable Chemistry & Engineering* 9 (32): 10857–67. https://doi.org/10.1021/acssuschemeng.1c03307.

128 DOE. "Greenhouse Gas Supply Chain Emissions Measurement, Monitoring, Reporting, Verification Framework." Updated March 15, 2024. https://www.energy.gov/fecm/greenhouse-gas-supply-chain-emissions-measurement-monitoring-reporting-verification-framework.

129 Congressional Research Service. "Inflation Reduction Act of 2022 (IRA): Provisions Related to Climate Change." Updated October 26, 2023. https://crsreports.congress.gov/product/pdf/R/R47262.

130 Bauer, C., Treyer, K., Antonini, C., Bergerson, J., Gazzani, M., Gencer, E., Gibbins, J., et al. 2022. "On the Climate Impacts of Blue Hydrogen Production." *Sustainable Energy & Fuels.* https://doi.org/10.1039/dlse01508g.

131 Congressional Research Service. "Inflation Reduction Act of 2022 (IRA): Provisions Related to Climate Change." Updated October 26, 2023. https://crsreports.congress.gov/product/pdf/R/R47262.

132 DOE. "Alternative Fuels Data Center: Biodiesel Income Tax Credit." October 22, 2004. Amended August 16, 2022. https://afdc.energy.gov/laws/396.

133 Life Cycle Associates. "GHG Analysis of Dry Mill for Corn Ethanol Production under IRA." December 1, 2022. https://growthenergy.org/wp-content/uploads/2023/02/LCA_-_45Z-EtOH-Default-FINAL.pdf.

134 GREET Model: https://greet.anl.gov/.

135 "Energy Policy Act of 2005." March 2022. https://www.govinfo.gov/content/pkg/PLAW-109publ58/pdf/PLAW-109publ58.pdf.

Independence and Security Act of 2007 established the second RFS, further amending the Clean Air Act and mandating that EPA expand the scope of the standard. Under the new policy, biofuels were required to be mixed with both gasoline and diesel, and EPA set GHG emissions reduction thresholds for biofuels. To qualify as renewable fuels, biofuels must have a life cycle GHG emissions intensity at least 20% lower than the fossil fuel baseline, with more stringent thresholds for advanced biofuels.[136] A study from the Argonne National Lab finds that life cycle GHG emissions reductions from biodiesel and renewable diesel produced from oilseeds and waste grease range from 40% to 86%, compared to petroleum diesel.[137]

Section 60108 of the IRA appropriates $5 million to the EPA to implement the RFS program through data collection and analysis for the LCA of biofuels and provides $10 million for new grants to support investment in advanced biofuels.[138]

C. Corporate Average Fuel Economy (CAFE) Standards

The National Highway Traffic Safety Administration (NHTSA) sets and enforces CAFE standards, and the EPA regulates emissions from passenger trucks and vehicles under Section 202 of the Clean Air Act.[139] CAFE standards date back to the Energy Policy and Conservation Act of 1975, which required the NHTSA to create a regulatory framework to help reduce emissions through improved vehicle fuel economy. As part of this process, the NHTSA publishes environmental impact assessments of its fuel economy standards, including LCAs of vehicle materials encompassing assembly, disposal, and recycling.[140] The NHTSA proposes fuel economy standards over different time periods based on the best information available at the time regarding which levels of stringency can be accommodated for vehicle model years.

D. Federal LCA Commons

The Federal LCA Commons is an "interagency community of practice" that promotes sharing and expertise related to LCA data, research, and information systems. Formalized through a memorandum of understanding between DOE, the EPA, and the Department of Agriculture, the Federal LCA Commons includes an interagency team of LCA experts across 12 government agencies.[141] Its stated goals are to advance federal LCA data, research, and information systems by leveraging resources across government agencies; to improve the consistency of LCA methods developed by each agency to develop results that can inform decision-making and public disclosure; and enhance public access to federal LCA data. The Federal LCA Commons includes data documentation across government agencies, a data handbook, training resources, and a collection of LCA datasets.

E. LCAs in International Policy

In gas-producing and consuming countries, some policymakers are calling for detailed information about the emissions intensity of natural gas and LNG. Governments are beginning to examine ways to track and reduce GHG emissions across natural gas supply chains, from production, G&B, transmission, liquefaction, and shipping to combustion. Increased focus on the emissions intensity of traded fossil fuels is creating new demands for GHG LCAs. However, policymakers

136 Congressional Research Service. "Calculation of Life cycle Greenhouse Gas Emissions for the Renewable Fuel Standard (RFS)." Updated March 12, 2010. https://crsreports.congress.gov/product/pdf/R/R40460/9.

137 Xu, H., Ou, L., Li, Y., Hawkins, T.R., and Wang, M. 2022. "Life Cycle Greenhouse Gas Emissions of Biodiesel and Renewable Diesel Production in the United States." *Environmental Science & Technology* 56 (12). https://doi.org/10.1021/acs.est.2c00289.

138 Congressional Research Service. "Inflation Reduction Act of 2022 (IRA): Provisions Related to Climate Change." Updated October 26, 2023. https://crsreports.congress.gov/product/pdf/R/R47262.

139 EPA. "Proposed Rule: Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light- and Medium Duty Vehicles." Retrieved on November 3, 2023. https://www.epa.gov/regulations-emissions-vehicles-and-engines/proposed-rule-multi-pollutant-emissions-standards-model.

140 National Highway Traffic Safety Administration. "Corporate Average Fuel Economy Standards, Model Years 2024-2026, Draft Supplemental Environmental Impact Statement." Docket No. NHTSA-2021-0054, August 2021. https://www.nhtsa.gov/sites/nhtsa.gov/files/2021-08/01_Summary_SEIS_CAFE_MY_2024-2026_web-tag_0.pdf.

141 Federal LCA Commons, LCA Commons Fact Sheet, February 2021. https://www.lcacommons.gov/sites/default/files/pdfs/Federal%20LCA%20Commons%20Fact%20Sheet_0.pdf.

must consider a number of items, including security of supply, information availability, and price, in their policy development decisions.

F. European Methane Legislation

The EU methane strategy published in October 2020 contained two major policy initiatives:[142]

- A global initiative to create an IMEO, as a collaboration between the UNEP and the commission, which would develop a Methane Supply Index against which emissions from individual companies would be judged
- Concentration on measurement, reporting, and verification (MRV) of methane emissions from imported gas, oil, and coal supply chains, but focusing initially on pipeline gas and LNG imports. This initiative proposed a diplomatic outreach campaign to persuade exporting countries to improve their MRV systems, the imposition of a default value for emissions should exporters fail to respond, and that: "in the absence of significant commitments from international partners, the commission will consider proposing legislation on targets, standards or other incentives for fossil energy consumed and imported in the EU."[143]

The analytical methods used by the European Union in developing the commission's proposed regulation were:

- The Greenhouse Gas and Air Pollution Information and Simulation (GAINS) model, an integrated assessment model of air pollutant and GHG emissions and their interactions
- The UNEP/Climate and Clean Air Coalition's Global Methane Assessment of May 2021, which includes results from five state-of-the-art composition climate models
- The International Energy Agency's Methane Tracker, a methane estimation tool for global emissions across the energy sector
- There is no reference to life cycle emissions analysis except in relation to agriculture and livestock.[144]

On November 15, 2023, Council of the European Union ("Council") and European Union Parliament reached a provisional agreement on regulating methane emissions from within the EU, as well as methane emissions associated with imports of LNG and natural gas.[145] [146] This follows the initial December 2022 Council proposal and the May 2023 Parliament version. The draft agreement has been codified into a draft regulatory proposal[147] released on December 15, 2023, and will undergo final approvals through the Council and Parliament before becoming final law around June 2024.

Since the EU imports more than 90% of its natural gas supply, the legislation also seeks to address methane emissions associated with imported gas. EU methane legislation will, in several phases, establish a methane transparency database for EU operators as well as imported gas, and introduce new MRV obligations for gas suppliers to the European Union.

The compromise draft introduces new requirements for importers of fossil fuels into the European Union. Regulations associated with import of LNG or gas will be implemented in three phases. The European Union will establish a methane transparency database, including "methane

142 European Commission. "Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee, and the Committee of the Regions on an EU Strategy to Reduce Methane Emissions." COM/2020/663 final, October 14, 2020. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52020DC0663.

143 European Commission. "Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee, and the Committee of the Regions on an EU Strategy to Reduce Methane Emissions." COM/2020/663 final, October 14, 2020. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52020DC0663.

144 European Commission. "Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee, and the Committee of the Regions on an EU Strategy to Reduce Methane Emissions." COM/2020/663 final, October 14, 2020. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52020DC0663.

145 European Commission. "Commission Welcomes Deal on First-Ever EU Law to Curb Methane Emissions in the EU and Globally." November 15, 2023. https://ec.europa.eu/commission/presscorner/detail/en/ip_23_5776.

146 European Commission. "Commission Welcomes Deal on First-Ever EU Law to Curb Methane Emissions in the EU and Globally." November 15, 2023. https://ec.europa.eu/commission/presscorner/detail/en/ip_23_5776.

147 European Parliament. "Reducing Methane Emissions in the Energy Sector – Q2 2021." Updated March 20, 2024. https://www.europarl.europa.eu/legislative-train/package-fit-for-55/file-reducing-methane-emissions-in-the-energy-sector.

performance profiles" on imports of fossil fuels into the EU markets. The methane performance profiles are proposed to be updated annually and should also include "a data quality assessment for reported methane emissions, including the level of OGMP 2.0 reporting."[148]

The draft clarifies importer data reporting requirements, timelines for international gas producers to comply with the regulation, how the European Union will approach an importer's contractual obligations, and how the European Union will evaluate exporting countries and companies' methane emissions measurement and mitigation for equivalence with the European Union. Further, the draft agreement outlines the purposes for four EU-managed programs: a Methane Transparency Database, Methane Performance Profiles, a Methane Emitters Global Monitoring Tool, and a Rapid Reaction Mechanism for detected super-emitters. For contracts concluded prior to entry into force, importers are only required to make "reasonable efforts" to comply with (yet to be defined) intensity standards. For new contracts (or those renewed) after entry into force, a six-year lead time is proposed until importers "shall demonstrate…that the methane intensity [of fossil fuels] …is below the maximum methane intensity values established…" This would mean that methane emissions intensity standards that imports are required to meet would not be in force until 2030.

G. Other European Union Legislation That May Lead to Developing LCAs

Aside from the European Union's proposed methane legislation, several other current and proposed policies will require more detailed methane emissions accounting. An extension of the EU Emissions Trading System will cover the maritime shipping industry.[149] The emissions trading system for shipping emissions will cover carbon dioxide beginning in 2024, and methane and nitrous oxide beginning in 2026. The MRV methodology with general rules for methane and nitrous oxide was adopted in May 2023.[150]

The European Union wishes to incentivize the growth of renewable and low-carbon fuels (such as green methanol) on ships to reduce life cycle GHG emissions, including CO_2, CH_4, and N_2O. FuelEU[151] will impose limits on the life cycle GHG emissions intensity of fuels used onboard and require certain ship types to have zero emissions at berth from 2030, with stringent financial penalties for noncompliance. This draft regulation forms a substantive part of the EU's "Fit for 55" package, which targets a reduction of net GHG emissions by 55% by 2030.

FuelEU requires reduction in life cycle (well-to-wake) GHG emissions intensity by 80% by 2050, indexed to 2020. Recent drafts of FuelEU have alternated between allowing direct measurement for fossil fuels or requiring the use of static emissions factors.

The EU Taxonomy is a classification system that aims to scale up sustainable investment by providing companies, investors, and policymakers with definitions for which economic activities are environmentally sustainable. By standardizing reporting requirements for green finance, the EU Taxonomy will be used by investors to compare companies' environmental, social, and governance disclosures.[152] The European Union considers specific gas activities as "environmentally sustainable" under the EU Taxonomy if the life cycle GHG emissions for activities that use fossil gaseous fuels computed using ISO or EU standards are below 100 g CO_2e/kWhr, and verified by an independent third party.[153] In addition, the fuel switching or replacement should be demonstrated

148 European Parliament. "Reducing Methane Emissions in the Energy Sector – Q2 2021." Updated March 20, 2024. https://www.europarl.europa.eu/legislative-train/package-fit-for-55/file-reducing-methane-emissions-in-the-energy-sector.

149 Council of the European Union, PE-CONS 10/23, April 20, 2023. https://data.consilium.europa.eu/doc/document/PE-10-2023-INIT/en/pdf.

150 Official Journal of the European Union, May 10, 2023. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32023R0957.

151 RC/Rz, JS. "PE-CONS 26/23." July 13, 2023. https://data.consilium.europa.eu/doc/document/PE-26-2023-INIT/en/pdf.

152 European Commission. EU Taxonomy for Sustainable Activities." n.d. https://finance.ec.europa.eu/sustainable-finance/tools-and-standards/eu-taxonomy-sustainable-activities_en.

153 For plants whose construction permit is granted before the end of 2030, the direct GHG emissions of the activity must be no more than 270 g CO_2e/kWh or annual direct GHG emissions of the activity do not exceed an average of 550 kg CO_2e/kW of the facility's capacity over 20 years.

to reduce emissions by 55% over the lifetime of the new gas power plant.

H. Interest in LCAs of GHG Emissions in Asia

Aside from North America and Europe, most of the early interest in LCA for natural gas has been centered in Northeast Asia, particularly in Japan and the Republic of Korea (South Korea)—two of the world's top three LNG importers.[154] There have been some corporate commitments and policy support in Japan and South Korea to reduce methane emissions associated with their gas supply chains, although these efforts are at an early stage.[155] Interest in LCA is nascent in Northeast Asia, especially as energy security and price concerns tend to drive gas procurement strategies. Elsewhere in Asia, these efforts are less advanced.

Japan's Ministry of Environment has imposed guidelines for the calculation and reporting of GHG emissions, including methane, defined by industry sectors and specific processes. These rules cover domestic production of natural gas but not imported gas. These guidelines are based on the 1998 Act on Promotion of Global Warming Countermeasures. To date, specific rules related to verification have not been included. In other Asian countries, these efforts are less advanced and mandatory rules for GHG emissions reporting are in various stages of development.

Japanese interest in GHG emissions from imported fossil fuels is growing, although more slowly than in North America or Europe.[156] Frameworks and systems to evaluate GHG footprints of different products more accurately are under consideration. Japan is expected to formulate a unified guideline of LCAs, likely based on ISO standards. The Japan Gas Association, or JGA, the industry association of the city gas suppliers, stipulates that its scope of LCA of natural gas—including imported LNG and domestic gas production—covers exploration and production, process and liquefaction, international maritime transport, regasification, domestic pipeline transportation, and final consumption (combustion).

Japanese LNG importers would like to gain access to more accurate information regarding LCAs of natural gas. Because multiple parties are involved in natural gas supply chains associated with U.S. LNG exports, it has not been easy for Japanese LNG importers to obtain primary information of the emissions intensity of purchased gas. Sometimes only secondary data have been available from theoretical calculations based on generalized operational data of upstream production facilities and LNG liquefaction plants.

JGA's latest analysis on LCA of GHG emissions for LNG and city gas, published in 2016, does not include LNG from the United States in its calculation, as primary data was not available then and Japan did not import LNG from the United States until the next year. JGA's LCA calculation for LNG and natural gas supply was originally introduced to compare their emissions profiles with those of oil and coal. Availability of data from the United States' upstream segment, as well as other segments of the supply chain, could promote renewals of LCA calculations for natural gas supply in Japan. While the Ministry of Economy, Trade, and Industry's draft report, referenced above, focuses on final and intermediate goods, it also deals with emissions footprints of energy sources, potentially leading to more calls from final energy users to provide more accurate data on indirect emissions.

As other Asian countries implement measures toward their nationally determined contributions, interest in LCA of natural gas supply could grow. However, interest among Asian gas buyers is still relatively low, especially among more price-sensitive buyers in South Asia and Southeast Asia. Concerns over cost and energy security still tend to outweigh interests in the emissions intensity and methane intensity of purchased gas.

In November 2023, the *Japan Climate Transition Bond Framework* was released, which outlines

154 "The LNG Industry GIIGNL Annual Report 2023." https://giignl.org/wp-content/uploads/2023/07/GIIGNL-2023-Annual-Report-July20.pdf.

155 "Launch of the Methane Emission Reduction Initiative (CLEAN) by KOGAS and JERA." July 18, 2023. https://www.jera.co.jp/en/news/information/20230718_1565.

156 Ministry of Economy, Trade, and Industry, Japan. "Carbon Footprint of Products Study Group Draft Report." January 2023. https://www.meti.go.jp/shingikai/energy_environment/carbon_footprint/pdf/004_05_00.pdf.

its Green Transformation plans, which aim for a 46% reduction of GHG emissions by 2030 from 2013 levels and carbon neutrality by 2050.[157] The use of LCA is still in development, as the overall bond framework (what the government will spend money on) but the initial draft requirements show that several aspects of the bonds[158] will likely use LCAs to measure the GHG emissions impacts of new infrastructure and energy projects. As many of the proposed covered activities are coal-to-gas switching, it is likely the use of LCA will be a key part of bond reporting over the coming decade.

I. International Cooperation on Methane MRV and Differentiated Gas

Numerous voluntary and industry-led initiatives have been created to assess emissions across natural gas supply chains. Voluntary initiatives include certified-gas schemes from private companies and LCAs of GHG emissions specific to corporate supply chains and export facilities.[159] As one example, the global LNG industry has published frameworks for GHG-neutral LNG cargoes, including guidelines for reporting the GHG footprint of individual cargoes as well as emissions reductions and offsets.[160] Sales of such LNG cargoes have now taken place using a framework published by the International Group of Liquefied Natural Gas Importers, as well as a methodology developed by Pavilion Energy, Chevron, and Qatar Energy. However, there have only been a few such transactions.

The proliferation of these initiatives presents challenges. Market-based certified-gas programs can cover broad geographies, encourage data collection, and expose gaps that operators can then address. But certified gas suppliers have been criticized for nontransparent methodologies.

In April 2023, the U.S.-EU Energy Task Force announced an intention to "develop an internationally aligned approach for transparent MMRV for methane and carbon dioxide emissions across the fossil energy supply chain."[161] The United States and European Union want to develop "a common tool for life cycle analysis of methane emissions for hydrocarbon suppliers and purchasers" and aim to improve the accuracy and transparency of emissions data at "cargo, portfolio, operator, jurisdiction, and basin level." Gas-importing countries in Asia have signaled some support for such efforts. In July 2023, Japan's Jera and South Korea's Kogas, the world's two largest LNG buyers, announced they would work to "increase the visibility of methane emissions through dialogue with LNG producers."[162]

The United States, the European Union, the East Mediterranean Gas Forum, and at least 15 other countries have formed a working group on MMRV for pipeline gas and LNG volumes. The goal is to develop a robust, transparent framework and harmonize existing MMRV standards and reporting frameworks to provide more certainty for gas purchasers. The working group aims to build upon existing protocols and standards but establish more consistent technical criteria. The working group is initially focusing on methane and carbon dioxide but could include other GHG emissions in the future. Key focus areas of the international working group include: verification and certification criteria for MMRV and differentiated gas, accreditation and issues associated with the technical qualifications and independence of gas certifiers; data transparency and dissemination tools; and coordination with various stakeholders.

157 https://www.meti.go.jp/policy/energy_environment/global_warming/transition/climate_transition_bond_framework_eng.pdf.

158 Ministry of Economy, Trade and Industry, Japan. "The Basic Policy for the Realization of GX: Reference Document." n.d. https://www.meti.go.jp/english/press/2023/pdf/0210_003c.pdf.

159 Roman-White, S.A., Littlefield, J.A., Fleury, K.G., Allen, D.T., Balcombe, P., Konschnik, K.E., Ewing, J., Ross, G.B., and George, F. 2021. "LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting." *ACS Sustainable Chemistry & Engineering* 9 (32): 10857–67. https://doi.org/10.1021/acssuschemeng.1c03307.

160 "MRV and GHG Neutral LNG Framework." 2021. https://giignl.org/wp-content/uploads/2021/11/MRV-and-GHG-Neutral-Framework.pdf.

161 U.S. Department of State. "Joint Statement on the U.S. - EU Energy Council." April 4, 2023. https://www.state.gov/joint-statement-on-the-u-s-eu-energy-council-2/.

162 Kogas and Jera. "Launch of the Methane Emission Reduction Initiative (CLEAN)." July 18, 2023. https://www.jera.co.jp/en/news/information/20230718_1565.

J. LCAs in Corporate Climate Strategies

In gas-producing and consuming countries, more policymakers are calling for detailed information about the emissions intensity of natural gas and LNG. Governments are examining ways to track and reduce GHG emissions across natural gas supply chains, from production, G&B, transmission, liquefaction, shipping, to combustion. Policymakers are also keen to compare the life cycle emissions footprint of natural gas compared to other energy sources. Increased focus on the emissions intensity of traded fossil fuels is creating new demands for GHG LCAs.

A GHG LCA can provide significant attributional insights to a corporate natural gas supply chain. Examples include: the attribution of a specific GHG (methane versus carbon dioxide), specific emissions sources (e.g., flaring, or fugitive emissions), specific activity data (e.g., shipping distance or pipeline distance), and specific technology (gas driven turbines versus coal-fired boilers). Supplier-specific LCAs have been shown in scientific literature to be capable of differentiating various supply chains, and hence, have the potential to discern the lower emitting pathways, or even gas suppliers at all stages.

While there is a growing interest in GHG-related LCAs from natural gas and LNG, the study finds there is limited usage of LCA models by stakeholders, and LCA expertise is limited to a small subset of oil and gas companies, national laboratories, and scientific institutions. The potential reasons include:

- The lack of historical regulatory or commercial GHG emissions mandates requiring a natural gas/LNG supply chain-focused analysis
- Public models are hard to use
- Supply chain mapping is difficult for the natural gas sector due to fragmentation of the supply chain and lack of data
- Complexity is more pronounced in the United States due to various participants in the gas supply (though the United States has a wealth of data through GHGRP and public databases)
- Complexities exist in LCA modeling versus experience with inventory-based methods in developing corporate climate strategies
- There is a lack of familiarity and expertise in LCA tools by industry operators

The study finds there are only a handful of natural gas firms that employ LCAs as part of corporate climate strategies. Some companies have developed bespoke LCA models based on empirical data collection, including data collected from various links in their supply chains.[163] Others estimate the CFP of their products by using a mix of proprietary data from their own operations as well as commercially available data.[164]

Companies conduct detailed LCA analysis for several reasons. Collecting granular, empirical data helps them pinpoint emissions throughout their supply chains. This enables examination of emissions reduction opportunities both in operated assets and other parts of the supply chain, which can enable discussions with suppliers and customers about their GHG emissions reduction opportunities. Companies can also leverage these data in relationships with their suppliers and customers, for example, in sharing data with their suppliers to help drive down their life cycle emissions.

Companies also recognize the growing demand from customers for LCAs of emissions. Some domestic natural gas consumers, including utilities and industrial players, are requesting greater transparency on the GHG emissions associated with purchased gas volumes. There is emerging interest among LNG buyers in understanding the emissions associated with purchased volumes. The market mechanisms to facilitate this trade are still developing, for example, explicit inclusion of emissions intensity assessments in LNG benchmarks and trading windows, or certificates

163 Roman-White, S.A., Littlefield, J.A., Fleury, K.G., Allen, D.T., Balcombe, P., Konschnik, K.E., Ewing, J., Ross, G.B., and George, F. 2021. "LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting." *ACS Sustainable Chemistry & Engineering* 9 (32): 10857–67. https://doi.org/10.1021/acssuschemeng.1c03307.

164 Shell Global Solutions (US) Inc. "The Net Carbon Footprint Model: Methodology (Public)." October 2021. https://fourleafdigital.shell.com/webapps/climate_ambition/downloads/the-net-carbon-footprint-model.pdf.

of origin that could verify the emissions intensity of individual LNG cargoes. Finally, companies are aware of policy momentum to expand LCAs of fossil fuels and want to develop such analytical capabilities.

While many oil and gas companies disclose emissions data and set goals for Scope 1, 2, and sometimes Scope 3 emissions, fewer have completed unique LCA studies of emissions from natural gas. A review of annual reports, sustainability reports, and investor presentations by a representative group of companies, including the supermajors, large independent exploration and production companies, national oil companies, and U.S. LNG producers, shows that relatively few make public mention of extensive LCA studies.[165]

As upstream producers, midstream companies, and LNG producers seek to measure, report, and verify their emissions as well as emissions reductions, it is possible they will employ LCAs more frequently in the future. Policies outlined in this section could encourage such analysis.

The line between Scope 3 reporting and LCA analysis is often blurred in corporate reporting, and few companies publish detailed data on product emissions footprints. There has been limited evidence on the use LCAs by companies in their respective corporate climate strategies, including Scope 3 reporting or sourcing of natural gas supplies based on empirical data collection.

K. Guidelines on Evaluation of LCA Results

Policymakers, corporate decision-makers, investors, regulators, and other stakeholders need to understand and use information about GHG emissions from across the natural gas supply chain. Such information can come from rigorous LCA studies using full LCA models, but the effort and time required to complete such studies is incompatible with the timescales required for certain decisions. Full LCA models are often complex, with hundreds to thousands of KMIs, and require strong LCA expertise. Recent measurement campaigns across the natural gas supply chain (mainly related to methane) produced empirical datasets consistent with recommendations outlined in the Section titled "Incorporating Measurements in LCAs" that could be used in lieu of datasets from traditional inventories. But these have seen very limited incorporation into LCA models due to multiple factors. Traditional inventories can provide useful information on GHG emissions from a facility or industry, but unlike LCAs, are limited to providing decision-makers with holistic net GHG emissions information, comparing supply chains or technologies. Sometimes LCA studies that have been completed by one party need to be evaluated by another party for their quality, relevance, and accuracy. LCA studies can also be used both in private (business sensitive) contexts as well as public ones.

Harmonization (systematic review and meta-analysis) of recently published LCAs of natural gas allows for a higher degree of transparency and comparability of their estimates of the CFP of natural gas. Moreover, it reduces uncertainty associated with estimates in the literature and better informs policymaking and research decisions. This process ensures consistency across studies and forms an initial set of minimum requirements for future natural gas LCAs. In addition, the effort of harmonization of prior published LCAs conducted as part of this study aids in informing the LCA user community of key practices that users should adopt to evaluate and compare LCA results. As noted earlier, even measurement studies generating empirical datasets need to be harmonized to ensure consistency in boundaries (gates), GWPs, coallocation of products, and units (e.g., intensity rates expressed as gas delivered from each stage versus gross production, as commonly used in measurement studies). The SLiNG-GHG model KMIs reflect the most influential parameters identified through the harmonization process. Another set of minimum requirements for evaluating natural gas LCAs reflects the list of KMIs chosen for the streamlined LCA model presented here and assessment against the default values used in this model. As supply chains evolve to reduce

165 Companies that publish LCA assumptions and methodologies include Chevron and Shell. See Chevron, "2022 Sustainability Performance Data," https://www.chevron.com/-/media/shared-media/documents/2022-sustainabilty-performance-data.pdf, and Shell, "The Net Carbon Footprint Model: Methodology (Public)." October 2021. https://fourleafdigital.shell.com/webapps/climate_ambition/downloads/the-net-carbon-footprint-model.pdf.

emissions, the importance of these parameters may change. Future LCAs should consider a materiality assessment of key emissions sources in each stage of its supply chain and assess against the default 24 emissions sources recommended by the NPC in the SLiNG-GHG model.

When evaluating LCA results from other studies or work, users are encouraged to review the harmonization process adopted in this study and assess results from such studies against the National Academies of Sciences, Engineering, and Medicine (NASEM)[166] Six Pillars:

- **Usability and timeliness:** NASEM recommends that GHG emissions information presented to decision-makers be relevant and support the decision-making process. In this study, NPC adopted a process whereby GHG emissions data from a systematic literature review was harmonized to allow for comparison between studies. The model provides reasonable estimates relative to other complex LCA models employed for evaluating life cycle GHG emissions intensities across the supply chains. The user-defined features, along with default values for the KMIs, as well as relative simplicity of the model design, enables the potential for greater use by stakeholders in a timely manner.
- **Information transparency:** NASEM recommends that the GHG emissions intensity results be publicly available and traceable. This study provides a template for transparency by making the model and its default inputs publicly available and providing guidance to users on the use.
- **Evaluation and validation:** NASEM calls for review, assessment, and comparison to independent datasets from other studies and research entities. In this study, NPC has outlined the harmonization process and evaluated the GHG emissions intensity results using default KMIs relative to outputs from external modeling teams. The NPC recognizes the limitations of the model but also understands the barriers related to greater adoption of full-blown LCA models, which motivated the model's development. The model can be enhanced by incorporating more measurement-informed datasets that meet scientific rigor and are aligned with specific needs of LCAs (e.g., self-consistent emissions and throughput measurements) to improve the existing default KMIs.
- **Completeness:** NASEM defines completeness to mean that GHG emissions information for the specific boundary has comprehensive spatial and temporal coverage. The model, by design, is not complete and does not cover every known emissions source. This limitation should be recognized by all users when utilizing the model. The model does include key segments of the natural gas supply chain to produce cradle-to-gate GHG emissions intensities but does not cover end use to produce cradle-to-grave GHG emissions intensity results.
- **Inclusivity:** NASEM defines inclusivity to mean whether the GHG information was generated by a larger group of stakeholders. The model development was led by McGill University and NREL and supported by dedicated experts from the NPC study. The model and its data input are publicly available.
- **Communication:** NASEM defines effective communication to mean that methodologies and assumptions of the GHG emissions results are described in understandable forms, well documented, and openly accessible. The model is not only documented as part of this NPC report, but also publicly available online. The accompanying user manual and webtool is meant to ensure effective communication with stakeholders to ensure continuous improvement of the tool.
- The model developed as part of this project aligns well with five out of the six NASEM pillars, with the exception being completeness. The structural design of the current model means it does not represent the full life cycle, as it does not include end use, in order to conform with the scope of the NPC study. Users should recognize this limitation and ensure that, for their use case, a streamlined model is appropriate. Further, the model's capability to allow for input of user-defined KMI values allows stakeholders to incorporate measurement-informed

166 National Academies of Sciences, Engineering, and Medicine. 2022. "Development of a Framework for Evaluating Global Greenhouse Gas Emissions Information for Decision Making." https://www.nationalacademies.org/our-work/development-of-a-framework-for-evaluating-global-greenhouse-gas-emissions-information-for-decision-making.

datasets relevant for their specific facilities in their specific region or country, thereby further improving the accuracy and usability of the model.

VII. SUMMARY OF FINDINGS & RECOMMENDATIONS

There is growing interest in understanding the life cycle impacts of natural gas and LNG. LCAs offer several significant and distinct benefits in the assessment of GHG emissions impacts from production, transportation, and use of natural gas. However, there has been limited adoption of LCA tools and models in public and corporate natural gas and LNG decision-making. The study team developed an open-source and accessible natural gas LCA model with transparent KMIs. The purpose of the SLiNG-GHG model is to provide a reasonable, publicly available screening-level estimate of life cycle GHG emissions for natural gas and LNG supply chains. NPC provides several recommendations to policymakers to improve current practices and issue guidelines on conducting LCAs and interpreting their results. If implemented, LCAs can be a powerful tool in providing fair and consistent comparisons of natural gas supply chains, and support public and corporate decisions on addressing GHG emissions from supply chains.

FINDING 1: Life cycle assessment (LCA) is an internationally recognized method for estimating potential environmental impacts of products such as an energy product (natural gas or liquefied natural gas) from wellhead to end use. While there is growing demand for LCAs in public policy and corporate strategies related to natural gas and LNG in the United States and internationally, there has been limited usage of LCA as a tool to inform public policy and corporate strategies to date. To demonstrate an approach that would enable wider use of LCA tools in public policy and corporate strategies across the natural gas supply chain, the NPC has developed an open-source, user-defined, simplified, and streamlined natural gas well-to-gate LCA model (SLiNG-GHG) that can support generation of reasonably representative, screening-level estimates of U.S.-based life cycle GHG emissions.

LCA concepts have been standardized with the publication of ISO standards.[167, 168, 169] GHG LCAs can support decision-makers with answers to GHG emissions intensities from the product or process across the supply chain or the net GHG emissions impacts from introduction of the product or process to the market.[170] There is growing interest in LCAs in the United States, European Union, and among certain Asian buyers.

However, the NPC finds limited usage of natural gas LCA models by stakeholders. LCA expertise related to the natural gas supply chain is limited to certain companies, national laboratories, and scientific institutions. This is likely due to the complexities of modeling, a lack of historical regulatory or commercial drivers for supply chain-focused analysis, a lack of expertise by policymakers and companies, and often incomplete data inventories.

An open-source and accessible natural gas LCA model with transparent KMIs that are updated at a regular interval with empirical data will allow for greater use of LCAs in public policies and corporate strategies while improving the accuracy of LCA estimates at the required boundary in the natural gas supply chain.

RECOMMENDATION 1: *The NPC recommends that DOE support the adoption of open-source, user-defined, simplified and streamlined*

167 ISO 14040. International Standard. Environmental Management-Life Cycle Assessment–Principles and Framework. International Organization for Standardization. Geneva, Switzerland. 1997. https://www.iso.org/standard/23151.html.

168 ISO 14044 International Standard. Environmental Management-Life Cycle Assessment–Principles and Framework. International Organization for Standardization. Geneva, Switzerland. 2006. https://www.iso.org/obp/ui/#iso:std:iso:14044:ed-1:v1:en.

169 ISO 14067: International Standard. Greenhouse Gases–Carbon Footprint of Products –Requirements and Guidelines for Quantification. International Organization for Standardization. Geneva, Switzerland. 2018. https://www.iso.org/standard/71206.html.

170 National Academies of Sciences, Engineering, and Medicine. 2022. "Current Methods for Life Cycle Analyses of Low-Carbon Transportation Fuels in the United States." Washington, D.C. National Academies Press. https://doi.org/10.17226/26402.

models such as the SLiNG-GHG model as part of its measurement, monitoring, reporting, and verification efforts (and through the Federal Life Cycle Assessment Commons interagency process) as an easy-to-use screening tool, especially for stakeholders who do not have the capacity to conduct detailed life cycle assessment modeling. The integration of measurement-informed or empirical datasets is a critical next step in improving life cycle assessment estimates.

FINDING 2: The NPC's SLiNG-GHG model may be used to develop a screening-level estimate of the life cycle GHG emissions of natural gas across the natural gas supply chain using a reduced number of key model inputs related to emissions sources. The capability of SLiNG-GHG was successfully demonstrated with national-scale estimates differing by less than 30% from detailed life cycle assessment models.

The NPC study constructed the SLiNG-GHG model focused on selected key emissions sources for the natural gas supply chain. The model was developed considering the results of more than 2,000 published LCAs, associated results from other relevant studies, and the judgment of study experts. The SLiNG-GHG model provides a screening-level estimate of the GHG footprint for the natural gas supply chain from production through three gates, with the following endpoints: Gate 1, interstate transmission; Gate 2, local distribution company; and Gate 3, the point of LNG delivery to a regasification facility. The model can be used by nonexpert audiences to develop their own screening-level LCA estimates with a publicly available tool based on a transparent set of limited number of material KMIs.

Recognizing the limitations of the model, in that it focuses on a subset of impactful KMIs, the study finds reasonable alignment between the central GHG emissions intensity estimates from the SLiNG-GHG model, the harmonization work, and outputs from four detailed modeling teams.

RECOMMENDATION 2: *The NPC recommends greater use and standardization of the SLiNG-GHG model by relevant stakeholders in federal and state agencies, private sector, and nongovernmental organizations as an initial screening test for reasonableness for natural gas well-to-gate carbon footprints.*

FINDING 3: The NPC's SLiNG-GHG model can be used to conduct contribution analysis to assess the impact of emissions sources and individual GHGs, and potential mitigation opportunities in each stage of the natural gas supply chain. A stagewise contribution[171] analysis of the SLiNG-GHG model national Reference case confirms methane emissions as an important GHG contributor in the natural gas and LNG supply chains, underscoring the need to monitor, measure, and mitigate methane emissions.

Assessing the contribution of each GHG (CO_2 and CH_4) in the SLiNG-GHG model's national Reference case, methane emissions account for a majority of total GHGs under both GWP100 and GWP20 for Gates 1 and 2 (at more than 50%) and is a significant relative to the total GHGs when considering Gate 3. Assessing the contribution of methane emissions to the model estimate of total GHGs, methane emissions account for 32%–54% of total CO_2e emissions on a GWP100 basis for the three gates explored in this study. Methane contributes less for Gate 3 for both destination case studies (34% and 32%, respectively, for Europe and Asia). Under GWP20, the impact of methane emissions is amplified, contributing 58%–78% of total CO_2e for the natural gas supply chain gates reviewed in this study.

Similarly, the SLiNG-GHG model results can be explored to illuminate the contribution of individual emissions sources to the total life cycle GHG emissions intensity at any boundary.

This result underscores the need to mitigate emissions across the supply chain. In addition,

171 In LCA, a contribution analysis is the exercise of estimating the individual contribution of any given emissions source or individual GHG or stage to the overall life-cycle emissions intensity. For example, in natural gas LCA, a contribution analysis could advise the contribution of methane emissions or a specific emissions source (e.g., flaring in production) to the overall GHG emissions.

carbon dioxide remains an important GHG emissions contributor, especially in the liquefaction, processing, shipping, and transmission segments, and therefore, targeted mitigation actions, such as CCS, reduced flaring, improvements in flaring, electrification, compressor efficiencies, etc., can support greater reductions.

RECOMMENDATION 3: *The NPC recommends use of life cycle assessments, including the SLiNG-GHG model, by relevant stakeholders to conduct contribution analysis of each GHG to screen the impact and potential mitigation opportunities in each stage of the natural gas supply chain.*

FINDING 4: **The SLiNG-GHG model was designed to flexibly enable screening-level assessment of life cycle GHG emissions intensity of different natural gas supply chains and assess future potential policy changes or adaptation of scientific measurements, all of which were demonstrated here in this study.**

The SLiNG-GHG model was used to assess the life cycle intensity of U.S. natural gas and LNG supply chains under four future emissions reduction pathways defined by the NPC in this study. The study finds that, relative to the baseline case, the GHG intensities are reduced by 38%–55% for the domestic natural gas supply chain (production through distribution) and 22%–42% for the LNG export cases by 2030.[172] The reduction potential grows to 48%–83% and 30%–75% by 2050 for the domestic gas and LNG supply chains, respectively. The pathway analysis shows more than 60% reduction in methane emissions intensities across all boundaries and pathways with modest reductions (less than 5%) in carbon dioxide intensities by 2030. Under the TIP reduction pathways, methane intensity reductions of more than 74% are estimated to be realized by 2050 with 28%–43% reduction in CO_2 intensities by 2050. More than 90% of the emissions reductions modeled in 2030 are attributed to methane emissions reductions across the supply chain for both the domestic and LNG supply chains (Gates 1–3). In the 2050 (TIP) scenario, methane emissions reductions continue to play a significant role along with electrification of some G&B facilities and transmission compressor stations and CCS at LNG liquefaction plants.

Most publicly available life cycle GHG models have been parameterized at the national level, with model input values identified to be representative of overall U.S. oil and gas operations. These models represented the best-in-time analysis of the GHG emissions of U.S. natural gas supply chains, when reliable and large-scale data on methane emissions were not available. The SLiNG-GHG model was used to assess the variability in GHG emissions intensities of specific supply chains under the Reference case. Relative to the national averages, supply chain results are estimated to range from 50% lower to 20% higher for Gates 1 and 2, and 40% lower to 15% higher for Gate 3. Methane emissions are a key contributor to the intensities for the Rockies to California supply chain, while carbon dioxide emissions from compressor stations in transporting gas from the Appalachia to the Gulf Coast (due to larger transportation distances and, therefore, more compression needed for the gas to move from the production basin to end use) negates its relatively lower methane intensity of the Appalachian basin. Our analysis also shows that CO_2 from flaring and midstream activities may be significant contributors to the GHG emissions intensities for the Permian to Gulf Coast supply chain. This illustrates the capabilities of LCA tools to provide a holistic review of various supply chain GHG emissions intensities and develop bespoke mitigation options.

While the SLiNG-GHG model's flexibility allows the user to modify the KMI input values to represent different scenarios, such as the six supply chains represented here, the quality of data used as an input into an LCA study is a critical component to be considered when assessing the results of a study. Geospatial emissions and operational datasets for use as KMIs for natural gas supply chains are currently available in a limited context and maintained by state regulatory agencies or the private sector. However, these datasets are not harmonized and are not readily usable in the context of geospatial LCAs that are necessary to fully assess the differences in GHG emissions intensities for various supply chains. With regard

172 Ranges reflect 100- to 20-year GWPs.

to data inventory selection and sources, the individuals conducting the LCA will require a level of subject knowledge and expertise to assess the relevance of the data selected for use in the study.

The NPC recommends that research on development of measurement-informed, geospatial LCA tools focus on:

- Developing subbasin, supplier-specific LCA tools to account for unique characteristics of U.S. oil and gas supply chains and incorporating appropriate confidentiality and security consideration in such assessments
- Annually updated database of input parameterization for LCAs that incorporate expanded availability of measurement data
- Enabling consistent harmonization of national-level LCA models with regional and basin-specific LCAs

The Secretary's study request notes the importance of identifying the highest-emitting supply chain segments to prioritize mitigation efforts. Geospatial LCA tools can directly provide insights to natural gas operators, regulatory agencies, and other stakeholders on high-impact emissions reduction opportunities. To enable widespread use, the geospatial LCA tool should be transparently developed through the scientific peer-review process and made publicly available. In addition, where applicable and practical, data inventories should aim to be available in public repositories, for stakeholder use. Development of geospatial LCA tools can be carried out through collaboration between national laboratories that currently lead LCA development and academic institutions with demonstrated expertise in measurements of GHG emissions. Alternatively, centers could be established at academic institutions with a charge to undertake recommended research activities and maintain a national resource base of tools, datasets, and other outputs.

RECOMMENDATION 4: *The NPC recommends use of life cycle assessments to assess the GHG emissions intensities of different supply chains and pathways. The NPC recommends that DOE sponsor research to develop measurement-informed, geospatial life cycle assessment tools that make use of ongoing and future availability of highly resolved geospatial GHG emissions datasets across the U.S. oil and gas supply chains.*

FINDING 5: There is limited integration of measurement-information datasets in life cycle assessments (LCAs). Integrating measurements into LCAs is challenging. Sensitivity analysis employing methane emissions data from two top-down measurement studies reinforce the versatility of the SLiNG-GHG model and the need for empirical datasets for use in LCA models. Operationalizing a global differentiated natural gas framework through a common Measurement, Monitoring, Reporting, and Verification (MMRV) program requires the ability to verifiably distinguish emissions across different global natural gas supply chains, a goal that the SLiNG-GHG model could support.

Recent LCA studies that incorporated methane emissions measurements in a limited manner indicate life cycle GHG emissions intensities from well to gate can have material differences in emissions intensities relative to using national default factors from conventional inventory programs such as the GHGRP. Furthermore, resource characteristics, operational practices, and the regulatory environment vary across the United States, resulting in significant differences in methane emissions by operator, state, and basin. Interpreting measurements, including uncertainties associated with measurements conducted at different spatial and temporal scales, to each unit process or KMI within the context of process-based LCA frameworks is challenging. In addition to the spatial and temporal boundary matching challenges, allocating observed emissions to different product streams requires knowledge of production or throughput volumes and resource composition at the time of measurement. This creates emissions estimates in different studies that are not directly comparable. Thus, reporting standards must be established to enable the use of measurement data to develop LCIs.

The default methane KMIs employed in the Permian to Gulf Coast supply chain Reference case

in the SLiNG-GHG model were compared to two cases,[173, 174] developed using empirically derived methane KMIs representative of the Permian to Gulf Coast supply chains for the three boundaries considered in this study. Top-down measurement studies often do not produce uncertainty ranges for each KMI used in an LCA. Public policy and regulations such as the GHGRP typically use a single datapoint (e.g., emissions factors for methane and carbon dioxide sources) to represent national or regional averages without uncertainty ranges. The SLiNG-GHG model developed in this study employs central estimates for methane from harmonization of relevant studies and uses GHGRP data as default methane KMIs for various supply chains evaluated in this study. Similarly, the sensitivity analysis used in this work employs basinwide, allocated methane emissions intensity estimates without uncertainty ranges due to lack of reporting by primary data sources.

Results suggest that a replacement of nationally representative default model input data with selected national or regional measurement data could significantly affect understanding of estimated life cycle GHG emissions. While exact impact varies, both sensitivity case studies suggest that the use of empirical data for methane has a greater impact on life cycle GHG emissions intensity for some geographies relative to others, a finding that would need more evidence from other regions to corroborate.

Methane emissions intensities from peer-reviewed or high-quality measurement studies may be incorporated into the SLiNG-GHG model, provided they are of sufficient spatial and temporal resolution to allow for appropriate integration (e.g., coallocation between oil and gas products, measurement boundaries etc.) and geospatial and operational datasets are generated in a manner that allows for development of inputs as replacements of the default values in the SLiNG-GHG model. While there is lesser uncertainty of carbon dioxide emissions relative to methane emissions across the supply chain, there is a need for improved empirical datasets.

RECOMMENDATION 5: *The NPC recommends that DOE sponsor the creation of a multistakeholder expert advisory group to meet periodically and create recommendations on integrating GHG emissions measurement data from multiple technologies across the natural gas supply chain into conventional life cycle assessment frameworks. Additional recommendations on the leadership, organization, and content of the guidelines are summarized in Appendix E-15.*

FINDING 6: Evaluation of GHG data presented in natural gas life cycle assessment (LCA) studies can be enhanced by the harmonization process presented in this study and the use of six pillars recommended by the National Academies of Sciences, Engineering, and Medicine.[175] Harmonization can illuminate the challenges with current ways LCA has been done to inform guidance to improve LCA methodologies and ensure consistency.

Policymakers, corporate decision-makers, investors, regulators, and other stakeholders need to understand and use information about GHG emissions from across the natural gas supply chain. Such information can come from rigorous LCA studies using full LCA models, but the effort and time required to complete such studies is incompatible with the timescales required for certain decisions. Sometimes LCA studies that have been completed by one party need to be evaluated by another party for their quality, relevance, and accuracy. The streamlined model developed here can serve both purposes. It can also be used both in private (business sensitive) contexts as well

173 Lu, X., Jacob, D.J., Zhang, Y., Shen, L., Sulprizio, M.P., Maasakkers, J.D., Varon, D.J., et al. 2023. "Observation-Derived 2010-2019 Trends in Methane Emissions and Intensities from US Oil and Gas Fields Tied to Activity Metrics." *Proceedings of the National Academy of Sciences.* 120 (17). https://doi.org/10.1073/pnas.2217900120.

174 Zhu, Y., Allen, D., and Ravikumar, A. "Geospatial Life Cycle Analysis of Greenhouse Gas Emissions from US Liquefied Natural Gas Supply Chains." ChemRxiv. 2024; doi:10.26434/chemrxiv-2024-9v8dw. This content is a preprint and has not been peer-reviewed.

175 National Academies of Sciences, Engineering, and Medicine. 2022. "Development of a Framework for Evaluating Global Greenhouse Gas Emissions Information for Decision Making." https://www.nationalacademies.org/our-work/development-of-a-framework-for-evaluating-global-greenhouse-gas-emissions-information-for-decision-making.

as public ones. The model can enable the user to make informed decisions.

Harmonization (systematic review and meta-analysis) of recently published LCAs of natural gas allows for a higher degree of transparency and comparability of their estimates of the CFP of natural gas. Moreover, it reduces uncertainty associated with estimates in the literature, and better informs policymaking and research decisions. This process ensures consistency across studies and forms an initial set of minimum requirements for future natural gas LCAs. The harmonization steps taken to ensure consistency across studies can form an initial set of minimum requirements for future natural gas LCAs. Another set of minimum requirements for future natural gas LCAs reflects the list of KMIs chosen for the streamlined LCA model presented here.

The model's KMIs reflect the most influential parameters identified through the harmonization process. As supply chains evolve to reduce emissions, the importance of these parameters may change. Future LCAs should conduct a materiality assessment of key emissions sources in each stage of its supply chain and assess against the default 24 emissions sources recommended by the NPC in the SLiNG-GHG model.

RECOMMENDATION 6: *The NPC recommends that when evaluating LCA results from other studies or work, users are encouraged to review the harmonization process adopted in this study and assess results from such studies the six pillars recommend by the National Academies of Sciences, Engineering, and Medicine. The NPC recommends the DOE initiates and publishes best practice guidelines to conduct natural gas life cycle assessments.*

FINDING 7: Most existing life cycle assessment (LCA) frameworks are limited to attributional analysis of GHG emissions, which identify the contribution of different stages or sources in the supply chain to total emissions and inform potential mitigation efforts. There is a lack of consequential LCA frameworks, which can be used to estimate the net impact of changes in the energy supply mix.

GHG LCAs can support decision-makers with answers to GHG emissions intensities from the product or process across the supply chain or the net GHG emissions impacts from introduction of the product or process to the market.[176] Attributional LCAs analyze environmental (in this case GHGs) impacts across the supply chain of the product (e.g., natural gas). This is the case presented in this study, as NPC seeks to understand the GHG emissions intensities of natural gas from different production basins to markets. Such LCAs do not consider how individual supply chains may impact other supply chains or the larger market. Consequentially, LCAs review the net environmental impacts of bringing the product to the market, accounting for how the marketplace would respond in terms of overall supply mix, for example, assessment of the net impacts from LNG exports or impacts of public policy on energy supply and emissions (e.g., impact of methane waste emissions charge in section 136(c) of the Clean Air Act under the 2022 amendment of the IRA). The SLiNG-GHG model is an attributional model, which attributes GHG emissions normalized to a functional unit (MJ of natural gas) at the end of the boundary or gate being studied.

A limited number of studies have explored the development of dynamic or consequential LCAs through approaches such as integrating LCAs with general or partial equilibrium models, macroeconomic models, or trade network models. These models have been independently developed and are typically not comparable because of a lack of harmonization on fundamental assumptions and transparency into modeling parameters and assumptions. Significant uncertainty remains in model results from consequential LCAs because of inherent challenges in modeling coupled energy-human systems. This is because geopolitical considerations dictate future policy outcomes and thus the evolution of the energy system. These uncertainties are typically explored using

176 National Academies of Sciences, Engineering, and Medicine. 2022. "Current Methods for Life Cycle Analyses of Low-Carbon Transportation Fuels in the United States." Washington, D.C. National Academies Press. https://doi.org/10.17226/26402.

a scenario-based assessment of future energy system pathways.

There is a need for standardized GHG consequential LCA frameworks, and the availability of associated models (like the NETL attributional LCA model or the Argonne National Lab GREET model), to support informed decision-making as to the net GHG emissions impacts. The Secretary's study request notes the importance of analyzing the impacts of natural gas relative to other energy sources, both domestically and internationally, and requests that the study discuss modeling frameworks used for consequential life cycle emissions analysis. The development of consequential LCAs that identify and analyze emissions associated with counterfactual scenarios is essential to analyze the impacts of natural gas. The Secretary's study request included a discussion of potential trade-offs associated with low-emissions natural gas. A consequential LCA model can enable cost-benefit and emissions-impact analysis associated with the evolution of natural gas markets under future policy scenarios. This will enable stakeholders, including policymakers, natural gas consumers, buyers, and operators to conduct scenario modeling and integrate GHG emissions impacts into decision-making.

The NPC also recommends that research on consequential LCA frameworks should include, but not be limited to, integrating energy models in natural gas/LNG with conventional life cycle emissions assessment, developing methods to incorporate empirical data within the consequential LCA framework, soliciting broad stakeholder feedback on model parameters, ensuring that all models are publicly available for stakeholder testing, and uploading and maintaining the model framework as a national resource. DOE national laboratories have a history of developing and maintaining LCA models for policy analysis, education, and other applications. Other options would be to evaluate if academic institutions or multi-institutional centers may be a more appropriate organization for developing such a resource. The DOE, or another agreed upon organization, would need to establish an open and transparent process for model development, soliciting stakeholder feedback, and maintaining public access.

RECOMMENDATION 7: *The NPC recommends that DOE sponsor research efforts to develop consequential life cycle assessment (LCA) models consistent with existing LCA frameworks to support analysis of the GHG emissions impacts of future natural gas use relative to other energy sources in the United States and around the world.*

Additional technical recommendations are provided in Appendix E-15.

Chapter 5

INTEGRATED ANALYTICS AND TRADE-OFFS: REDUCING GREENHOUSE GAS EMISSIONS IN THE NATURAL GAS SUPPLY CHAIN THROUGH 2050

OVERVIEW

This chapter presents multiple sets of analyses that draw together and integrate those of the prior chapters, while also articulating the trade-offs surrounding different approaches to reducing greenhouse gas (GHG) emissions from natural gas supply chains. This chapter includes:

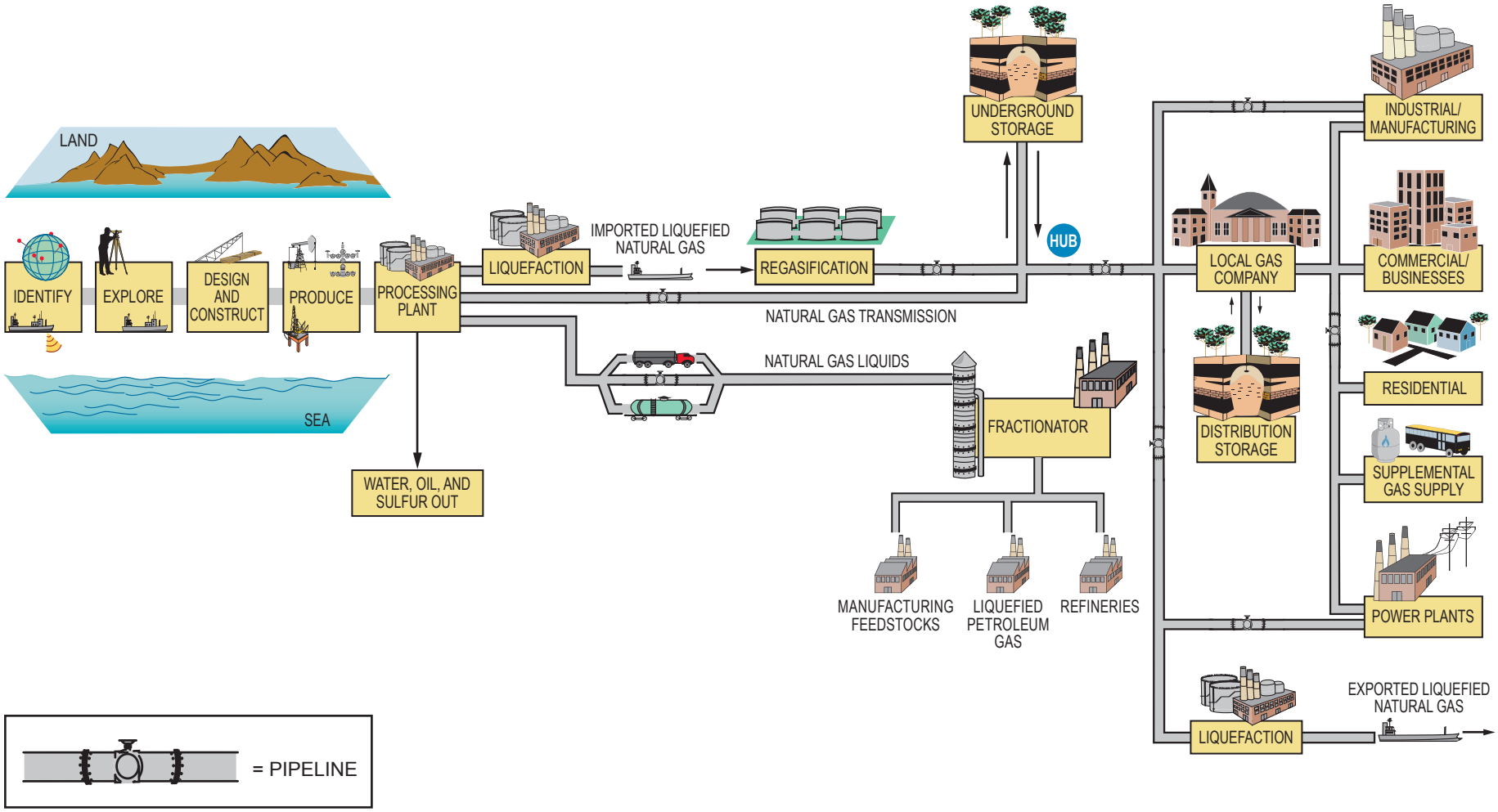
- Review of *natural gas supply chains,* focusing on the uniqueness and complexity of different supply chains and the resulting GHG emissions reduction opportunities
- Summary of the *scenarios analysis* used in this report, highlighting the evolving role of natural gas supply and consumption and how that will impact emissions trajectories
- Assessment of *recommendation themes and actions* in this study, focusing on the impact and feasibility of different recommendations, as well as highlighting the sequencing and path forward
- Recommendations for *charting the course* for reducing GHG emissions from natural gas supply chains, including recommendations on:
  - Durable policy
  - Market mechanisms
  - Differentiating low GHG intensity gas
  - Enhancement of societal and community benefits, and impact mitigation
  - International recognition for lower-emissions intensity liquefied natural gas (LNG)

To identify these recommendations and the holistic path forward, trade-offs between different approaches were assessed, focusing on the balance between their impact and feasibility. This approach resulted in recommendations that draw on a broad and diverse set of themes, including generating incentives for GHG emissions mitigation; improving the effectiveness of regulations; expanding government programs; increasing geopolitical and societal and community engagement; promoting technology advancement and industry coordination; and encouraging the development of oil and gas operator capabilities. All these recommendations also draw on a broad toolkit of direct emissions abatement actions, as well as recommendations that can help to enable emissions reductions.

I. NATURAL GAS SUPPLY CHAINS

A. Description of Supply Chains

Understanding what drives GHG emissions across natural gas supply chains and what measures can be taken to minimize those emissions begins with a clear and consistent characterization of those supply chains. The United States has one of the largest and most extensive natural gas supply chains globally, which plays a crucial role in meeting the energy needs of the country and supporting various industries. This supply chain is also subject to economic, regulatory, and environmental challenges that require ongoing management and adaptation. Modeling of natural gas supply chains for the purpose of measuring and reducing GHG emissions requires an understanding of the phases of natural gas exploration/production, processing, and distribution. That process is depicted in Figure 5-1.



Source: American Petroleum Institute, October 2013, "Oil and Natural Gas Industry Preparedness Handbook."

Figure 5-1. *The U.S. Natural Gas Supply Chain*

1. Exploration and Production

There are four steps in the exploration and production process:

1. **Identify**: Geoscientists and engineers use sophisticated technologies and techniques to find oil and natural gas under the Earth's surface. Before drilling, they use topographical maps, aerial photography, sound waves, 3-D projections, and other tools to estimate the size, shape, and consistency of the oil and natural gas that lies beneath the Earth's surface.
2. **Explore**: When an oil/natural gas prospect has been identified and evaluated, one or more exploration wells are drilled to conclusively determine the presence or absence of oil or natural gas in commercial quantities.
3. **Design and construct**: The goal of the well design process is to ensure safe and environmentally sound production of hydrocarbons by containing them, protecting groundwater resources, and isolating the productive formations. Proper execution of hydraulic fracturing and other stimulation operations may be needed to accomplish this goal.
4. **Produce**: Oil and natural gas production includes drilling, extraction, and recovery of resources underground, either onshore or offshore. Every oil and natural gas production facility is different. The size, shape, and design match the climate and characteristics of the location, as well as the type of reservoir and specific hydrocarbons within it.

2. Processing

Processing operations are designed and constructed to handle the hydrocarbon characteristics, expected flow rates, and lifetime.

Processing plant: Processing plants purify produced natural gas by separating impurities and the various hydrocarbons and fluids. This process produces what is known as pipeline-quality dry natural gas, which consists mostly of methane. A fully operational processing plant delivers pipeline-quality dry natural gas that can be used as fuel by Residential, Commercial, and Industrial consumers.

Fractionator: The fractionation process separates natural gas liquids (NGLs) into their base components. Common purity components of NGLs include ethane, propane, and butane. Fractionation occurs in stages, separating each purity component from the stream of mixed NGLs, one by one.

3. Transmission, Storage, and Distribution

The processed natural gas then needs to get to the market.

Pipeline: The U.S. natural gas pipeline network is a highly integrated transmission and distribution grid that can transport natural gas to and from nearly any location in the contiguous United States. Pipelines are categorized as interstate or intrastate. Interstate pipelines are long-distance, high-capacity pipelines that transport natural gas across state borders throughout the nation. Intrastate pipelines are contained within the border of a state and link natural gas producers to local markets and the interstate pipeline system.

Underground storage: Natural gas is stored in three principal types of large underground storage systems: depleted reservoirs, aquifers, and salt caverns. More than 80% of natural gas storage capability consists of depleted reservoirs, which are relatively easy to convert to storage facilities after use and are typically located near consumption centers and existing pipeline systems.

Distribution hubs: Natural gas hubs are locations where natural gas is priced and traded throughout the country. These market hubs are located at the intersection of major pipeline systems. The principal hub within the United States is the Henry Hub in Louisiana.

4. Liquefied Natural Gas

Liquefying natural gas provides a means to ship large quantities over a long distance.

Liquefaction: Liquefaction is the physical conversion of a gas into a liquid state. Liquefaction occurs at normal atmospheric pressure by supercooling the natural gas to -260°F, creating liquefied natural gas (LNG).

Shipping: LNG shipping provides a low-cost, safe, and reliable method of moving large volumes of natural gas long distances. LNG is transported in cryogenic tanks on double-hulled ships. LNG carriers are among the safest in the shipping industry, having made more than 100,000 voyages without major incident.[1]

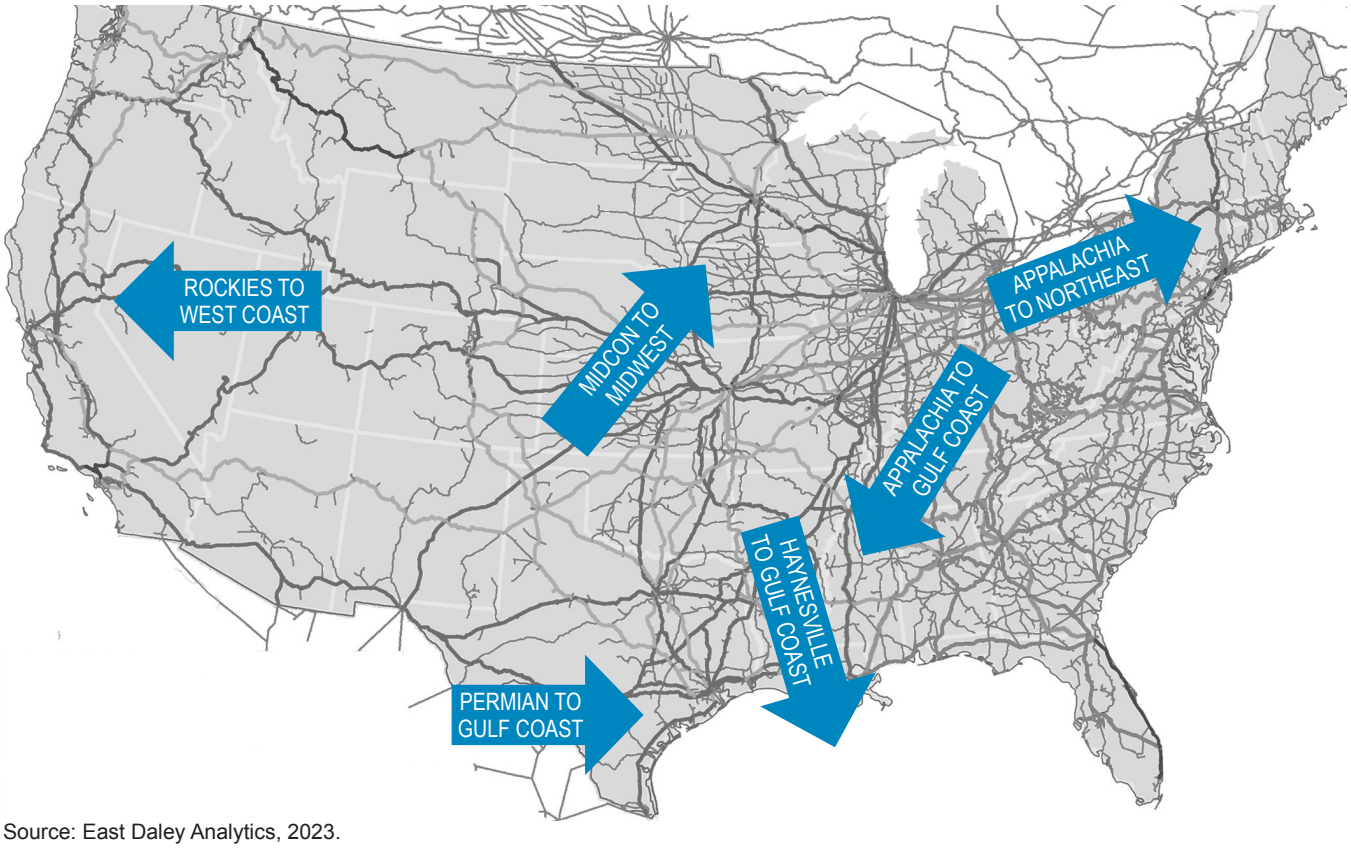
Regasification: Regasification is the process of transforming LNG into a gaseous state through vaporization, preparing it for use. The process occurs at regasification plants, where the temperature of LNG is increased, typically through seawater vaporizers, transforming it into gas.

B. Supply Chain Case Studies

Any given natural gas supply chain will combine elements of the above steps in a unique combination. To assess how supply chains function in practice and to highlight the differences in GHG emissions intensity across supply chains, this study developed and utilized a set of supply chain case studies. Evaluation and selection of supply chains for these case studies included a review of natural gas production and use to provide a diverse representation of the overall U.S. market. When selecting the supply chains to focus on within the study, the following criteria were considered: geographic footprint of the producing area, volume produced, infield production requirements (considering parameters such as associated and nonassociated gas), gathering capacity, distance-to-market, and different end uses (including local distribution and LNG).

The combined set of six supply chains in Figure 5-2 were used in the modeling for this study as a representative selection of supply chains in the United States. These six supply chains currently account for a majority of the U.S. pipeline-quality gas production that is transported between regions.

1 American Petroleum Institute. 2016. "Liquefied Natural Gas Exports." https://www.api.org/oil-and-natural-gas/energy-primers/lng-exports.



Source: East Daley Analytics, 2023.

Figure 5-2. *U.S. Natural Gas Supply Chain Case Studies*

The average utilization of pipelines was 77% in 2023 for the combined set of supply chains. In 2019, the combined set of supply chains accounted for just 42% of U.S. pipeline-quality natural gas production. Due to production growth from areas like the Permian Basin and Haynesville being shipped primarily to the Gulf Coast, the combined set of supply chains now accounts for 52% of U.S. pipeline-quality natural gas production and is expected to be sustained at that level until 2026.[2]

The Permian Basin supply chain is currently at 100% utilization, which can constrain producers' ability to bring on new volumes. That utilization disrupts the broader Permian Basin to Gulf Coast supply chain (through unplanned downtime, weather events, scheduled maintenance, etc.), resulting in a large impact to in-basin offtake. When the gas cannot be transported out of the basin, the reduced in-basin gas offtake can also incentivize some producers to flare, rather than shut-in, oil production.

This study employed data that the U.S. Energy Information Administration (EIA) uses for its *Natural Gas Annual* reports,[3] as well as additional key performance indicators identified during the life cycle assessment (LCA) harmonization effort. Starting with EIA data for gas supply and demand, this study required additional detail at a more granular level to estimate GHG emissions. This was accomplished by defining characteristics for supply chains linking strategic natural gas production to key demand centers[4] to compile a dataset for the six supply chains. To provide the data at a more granular level than what is available through EIA, the study team employed the services of East Daley Analytics. That company utilized its in-house production model to provide historical gross production volumes, an estimate of processing capacity that is derived from data reported to the EIA, and supply chain flows estimated by nomination data for the regions. The well count for each basin was collected by Well Database, leveraging well data reported by each state. Pipeline distance for gathering systems and long-haul interstate transportation was provided by RexTag.

Each of the six supply chains in Figure 5-2 are divided into three components: upstream, midstream, and downstream. The analysis and data generation on the six supply chains, using the following methodology, accounts for 52% of the domestic U.S. natural gas market. The following sections provide further detail as to how each supply chain was defined and highlight aspects that make each supply chain unique.

Gas consumption in each gas-producing region was estimated from EIA data as follows: Lease fuel (MMscf in 2022) was normalized with respect to total marketed production to obtain the fraction of gas that is combusted during the production and gathering phases of the natural gas life cycle. EIA does not report these volumes for individual gas plays. To approximate the gas consumed, the study employed volumes from the following states:

- Appalachia to Northeast: Pennsylvania
- Appalachia to Gulf Coast: Pennsylvania, West Virginia, and Ohio
- Haynesville to Gulf Coast: Louisiana
- Rockies to West Coast: Wyoming, Utah, and Colorado
- Midcon to Midwest: Oklahoma
- Permian to Gulf Coast: New Mexico

The top two supply chains in Table 5-1 are the Haynesville to Gulf Coast (GC) and Appalachia to GC chains. They account for 18% and 12% of the U.S. pipeline-quality natural gas[5] production, respectively. These two supply chains are gas-focused basins and account for 30% of U.S. production.

The average utilization across the combined supply chains conceals constraint issues that occur within specific supply chains. Appalachia is the largest single supply source. It is currently close to 90% utilization. The lack of infrastructure reduces the ability for the transportation

2 East Daley Analytics. NPC Supply Chain Analysis for *Charting the Course* report. 2023.

3 EIA. "Natural Gas Annual." 2022. https://www.eia.gov/naturalgas/annual/pdf/nga22.pdf.

4 East Daley Analytics. NPC Supply Chain Analysis for *Charting the Course* report. 2023.

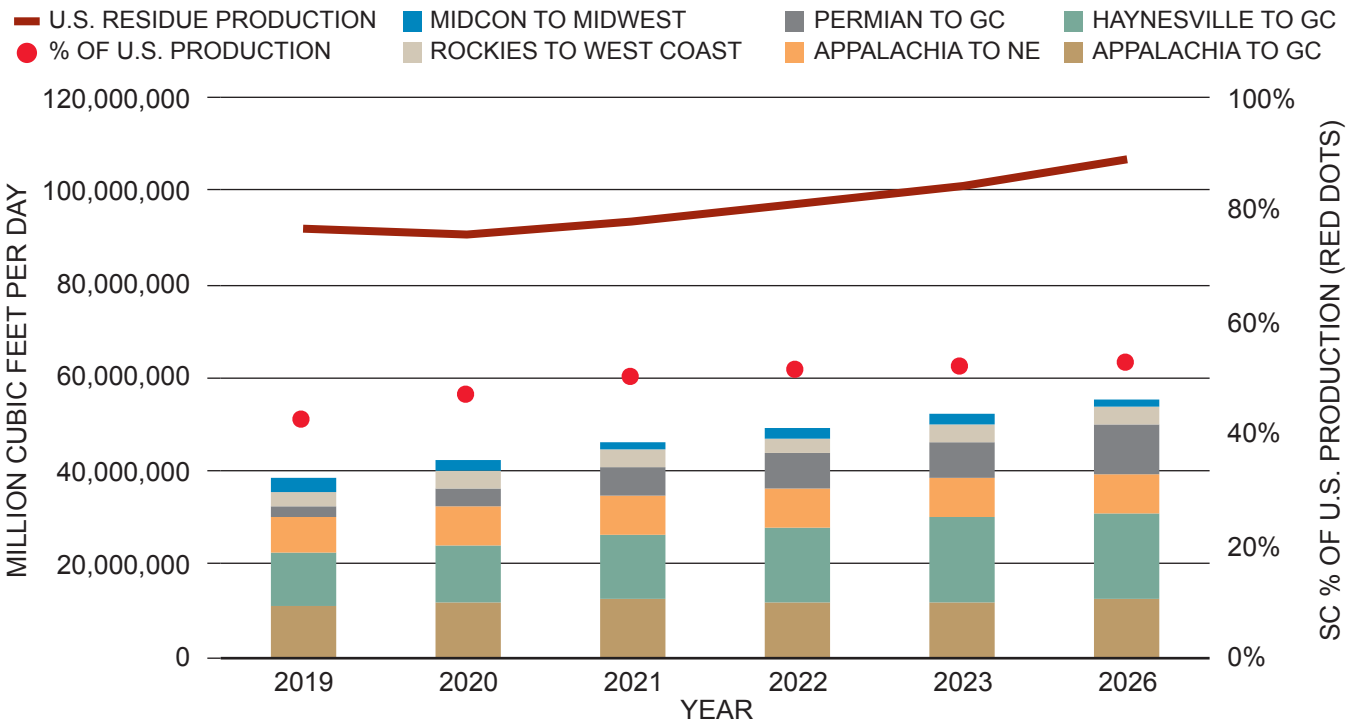
5 Pipeline-quality natural gas: Produced natural gas that has been processed to meet market specifications.

Supply Chain Summary (as of 2023)				
Region: Units (Mcf/d)	**Flow**	**Capacity**	**Utilization**	**% of U.S. Production**
Haynesville to GC	18,362,427	24,069,333	76%	18%
Appalachia to GC	11,987,154	13,735,751	87%	12%
Appalachia to NE	8,129,036	9,090,000	89%	8%
Permian to GC	8,037,859	8,071,250	100%	8%
Rockies to West Coast	3,466,234	6,551,000	53%	3%
Midcon to Midwest	2,233,086	5,969,000	37%	2%
Total of 6 Supply Chains	52,215,795	67,486,334	77%	52%
U.S. Pipeline Quality Natural Gas Production	101,065,831			

Source: East Daley Analytics, 2023.

Table 5-1. *Six Supply Chains Account for More Than 50% of U.S. Production*

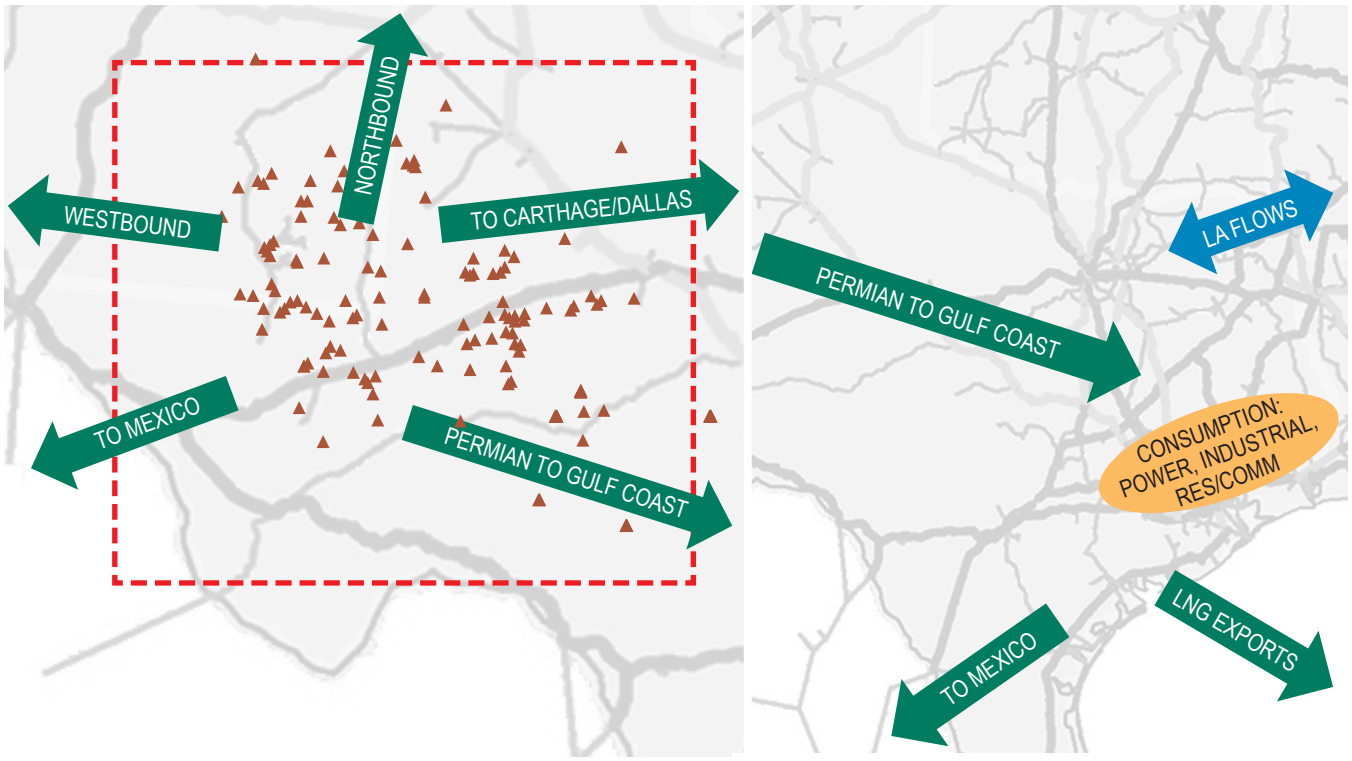
network to react to downtime and maintenance events in a cost-effective manner. The Permian Basin supply chain is currently at 100% utilization, which can constrain producers' ability to bring on new volumes. Additionally, any upset within the Permian Basin to GC supply chain (unplanned downtime, weather events, scheduled maintenance etc.), may impact the in-basin offtake. The reduced in-basin gas offtake can also incentivize some producers to flare rather than shut-in oil production, since the gas cannot be transported out of the basin.



Note: Actual data through April 2023, then forecasted onward through 2026.

Source: East Daley Analytics, 2023.

Figure 5-3. *Supply Chain Growth*



Source: East Daley Analytics, 2023.

Figure 5-4. *Permian Basin to Gulf Coast Supply Chain*

Figure 5-3 depicts the increase in production from the six supply chains over time.[6]

1. Permian Basin to Gulf Coast

The Permian Basin is the largest oil and gas basin in the United States. It produces more than 5 million barrels of oil per day and nearly 19 billion cubic feet per day (Bcf/d) of natural gas. Production grew at a rate of more than 15% per annum from January 2018 to June 2022. Over this period, flaring levels decreased by about 70% from historic highs in 2018 to the first half of 2022 (1H 2022) or by more than 420 million standard cubic feet per day (MMscf/d). Flaring peaked in 2019 Q3 at 642 MMscf/d or 4.2%, and average flaring per barrel of oil produced in the Permian has decreased from 140 cu ft/bbl in 2018 to 50 cf/bbl. Flaring was at 1.2% in 1H 2022. A lack of egress pipelines was cited as a key driver for increased flaring during 2018-2019. This has been mitigated after the GCX, Permian Highway, and Whistler pipelines came online through 2021.[7]

Long-term demand from LNG export terminals supported the expansion of pipeline takeaway capacity that led to flaring reductions, and further pipeline buildouts are necessary to sustain and expand flaring reductions.

Figure 5-4 shows that production in the Permian Basin comes from two main subregions: the Delaware Basin and Midland Basin and where the gas is transported. While gas can be marketed and sold to multiple regions of the country from the Permian Basin, the focus of the study was on the production and infrastructure required to supply the GC corridor located in Texas. That is where most of the Permian Basin gas is consumed. For this evaluation, the Permian Basin to Gulf Coast supply chain includes all gas produced in the Midland Basin along with the remaining volume of gas provided from the Delaware Basin. In the Permian

6 Chart provided by East Daley Analytics based on EIA natural gas production data.

7 East Daley Analytics. NPC Supply Chain Analysis for *Charting the Course* report. 2023.

Basin, more than 97% of gas production requires processing to remove natural gas liquids and impurities. As reported by EIA in New Mexico, 2.5% of total marketed production was assumed to be consumed as lease fuel. Most Permian Basin gas production is associated with oil production (i.e., associated gas). This associated gas requires a more energy-intensive process to make pipeline-quality gas than does nonassociated gas production. Infield energy use for the Permian Basin is higher than nonassociated basins, primarily due to extra fuel required for recompression to pipeline pressure and processing.

Flared volume is calculated as the total pipeline-quality gas production in the basin, minus gas consumed in and transported out of the Permian Basin. Flaring can increase as pipeline capacity becomes constrained, which was seen in 2019. By 2026, pipeline capacity is expected to increase from new projects and adding capacity to existing projects, and is expected to be sufficient to enable Permian Basin oil and gas production without constraints.[8] However, if gas production grows faster or pipeline projects are delayed in approval or construction, there is potential for gas flaring to increase or for production to be shut-in. Long-haul pipelines that move pipeline-quality gas from the region toward the Gulf Coast include Kinder Morgan Texas, Oasis, Enterprise West Texas, Guadalupe, Gulf Coast Express, Permian Highway, Whistler, and Matterhorn.

2. Appalachia to Gulf Coast

Figure 5-5 shows that the Appalachian Basin production from the Marcellus/Utica gas formations comes from four regions: Ohio, West Virginia, Southwest Pennsylvania, and Northeast Pennsylvania. That production includes all pipelines that move gas south from Ohio, West Virginia, and Pennsylvania, which includes Transco, TETCO, Columbia Gulf, Columbia Gas (TCO), ANR/Rover, and Trunkline. For this evaluation, the Appalachia to Gulf Coast supply chain is gas produced in the Ohio and West Virginia subregions; approximately 50% of gas production is considered wet gas and requires gas processing for the gas to be marketed. The remaining volume of gas is nonassociated and does not require gas processing, because the gas produced is dry gas that only requires gathering/dehydration to be marketed. Infield energy use is estimated to be 3.1% of marketed production based on EIA's reported lease fuel consumption in Pennsylvania, West Virginia, and Ohio. Since 50% of production in this region requires processing, the composition of gas is split between associated and nonassociated gas production, meaning a portion of the gas (associated) requires processing (i.e., additional fuel) while the remaining production does not require processing or infield energy use. The Appalachian Basin, therefore, has marginal flaring since gas production is a primary focus for the development. Producers choose to shut-in production rather than flare during operational upsets or capacity constraints.

Source: East Daley Analytics, 2023.

Figure 5-5. *Appalachian Basin to Gulf Coast Supply Chain*

3. Haynesville to Gulf Coast

Figure 5-6 shows that the Haynesville Basin or ArkLaTex Basin, is a producing area located in East Texas and Northern Louisiana that includes

8 East Daley Analytics. NPC Supply Chain Analysis for *Charting the Course* report. 2023.

Source: East Daley Analytics, 2023.

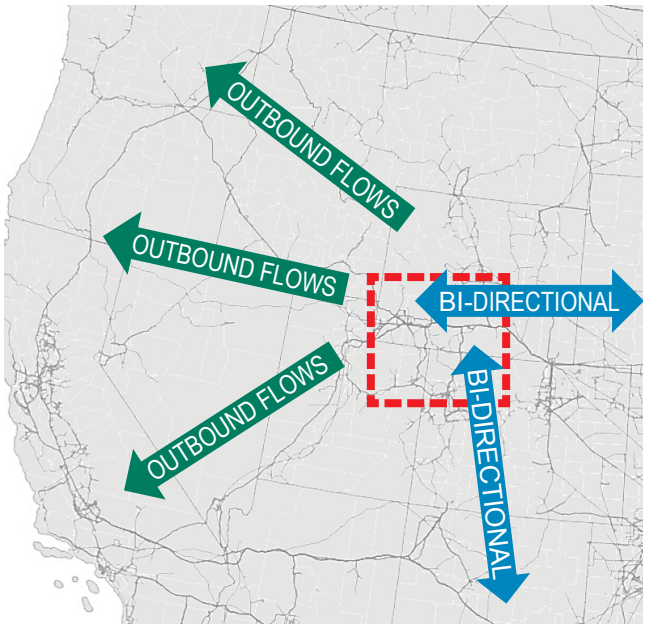
Figure 5-6. *Haynesville Basin to Gulf Coast Supply Chain*

gas production from formations such as the Haynesville, Bossier, and Cotton Valley. Cotton Valley gas tends to be rich in liquids and requires gas processing, while Haynesville and Bossier gas is dry and typically does not require gas processing before entering the market. The location of the basin means the infrastructure must support both the produced volumes and inbound supply by pipeline from other regions like Oklahoma, Barnett, and Appalachia. A significant amount of inbound supply that flows through the region to the Gulf Coast is commingled with Haynesville Basin production on pipelines such as Columbia Gulf, ANR, Midcontinent Express, and Natural Gas Pipeline of America, LLC (NGPL). Additional pipelines used to transport production in this supply chain include Acadian, Louisiana Intrastate Gas (LIG), DT Midstream LEAP Gathering Lateral pipeline, Gulf Run, Louisiana Energy Gateway (LEG), Tennessee (TGP), Momentum NG3, Gulf South, Texas Gas, Trunkline, Midla, Sonat, Texas Eastern Pipeline (TETCo), Southeast Supply Header (SESH), Houston Pipeline (HPL), Midcoast CJ Express (Midcoast), and KM Tejas.

For this evaluation, the Haynesville to Gulf Coast supply chain is gas produced within East Texas and Northern Louisiana and excludes volumes flowing through the region from other production areas. With the increase in dry gas production from the Haynesville and Bossier Formations, most of the gas produced in this area does not require processing. Infield energy is estimated to be 1.5% of marketed production based on EIA's estimate of lease fuel consumption, because most production in the Haynesville is nonassociated. That means that only gathering is required for the gas to be pipeline-quality. Haynesville has marginal flaring since gas production is a primary focus for the development, therefore producers choose to shut-in production rather than flare during operational upsets or capacity constraints.

4. Rockies to West Coast

Figure 5-7 shows that three basins account for most of the natural gas production in the Western Rockies: the Green River-Overthrust in Wyoming, the Piceance in Colorado, and the Uinta in Utah. Natural gas production is generally liquids rich and requires processing before entering



Source: East Daley Analytics, 2023.

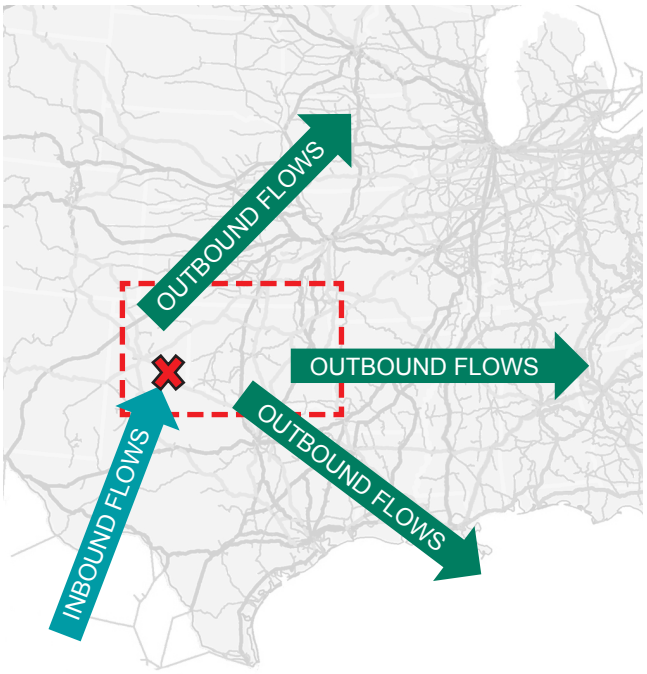
Figure 5-7. *Rockies to West Coast Supply Chain*

transmission pipelines. Gas production in the Western Rockies has generally been in decline since 2015. Gas-focused drilling reached a peak in 2011 when operators were pursuing gas and liquids in the Piceance and areas of the Jonah and Pinedale fields in the Green River-Overthrust. Three major gas pipelines (Kern River, Ruby, and Northwest Pipeline) move baseload supply to Pacific Coast demand, mainly in California and the Pacific Northwest. Rockies Express Pipeline (REX) was constructed to move gas east to the Midwest when production peaked. However, with declining supply from the Western Rockies and increased supply from Appalachia, REX has switched to moving gas supply bidirectionally depending on the season. During the winter of 2022/2023, REX sourced gas supply from the Utica, Midwest, and DJ Basin and shipped as much as 0.7 Bcf/d into the Western Rockies for delivery to major pipelines moving to the Pacific Coast.

For this evaluation, the Rockies to West Coast supply chain is gas flowing outbound from Wyoming, Colorado, and Utah and excludes seasonal inbound gas from the Midwest. Gas production in the Rockies is generally associated with NGLs and oil production. This requires processing wherein infield energy is estimated to be 2.6% of marketed production based on EIA's estimate of lease fuel consumption in Wyoming, Utah, and Colorado during production and gathering. Since gas production is a primary focus of development in the Western Rockies, that region has marginal flaring. Therefore, producers in that region choose to shut-in production rather than flare during operational upsets or capacity constraints. NGLs account for a significant amount of value for most produced volumes in the Western Rockies.

5. Midcon to Midwest

The Midcontinental (Midcon) production area (Figure 5-8) is defined as all of Oklahoma, the Texas Panhandle, and the Kansas counties along the Oklahoma border. Most of the gas produced in Midcon is either consumed in Oklahoma, transported southeast to Texas, or transported east to Arkansas. Gas production in Midcon is comprised mostly of the Anadarko Basin in Oklahoma, Texas, and Kansas, and the Arkoma Basin in Southeast Oklahoma. The Anadarko Basin is



Source: East Daley Analytics, 2023.

Figure 5-8. *Midcon to Midwest Supply Chain*

often segmented into subplays such as the South Central Oklahoma Oil Play (SCOOP), the Sooner Trend (oil field), Anadarko Basin, Canadian and Kingfisher counties (STACK), the Granite Wash, the Cana-Woodford, and the Mississippi Lime. Most Anadarko Basin gas production is liquids rich and requires gas processing. Most of the gas production in the Arkoma is dry gas production, which does not require processing.

However, more recent development in the SCOOP area has required gas processing development in areas of the Arkoma Basin. Pipelines for this supply chain include ANR, NGPL, NNG, Panhandle (PEPL), and Southern Star. This area contains a high mileage of gathering lines due to older low-pressure gathering systems, in addition to newly constructed high-pressure gathering to facilitate horizontal drilling development. Gas production in Oklahoma is split between associated and nonassociated production depending on location. Gas production in eastern Oklahoma (Arkoma Basin) is generally nonassociated and dry production, while gas production in the SCOOP, STACK, and Granite Wash areas is associated with oil and NGLs and requires processing in addition to gathering infrastructure. For this

evaluation, the Midcon to Midwest supply chain excludes inbound gas from other production areas. The infield energy is estimated to be 2.4% of marketed production based on EIA's estimate of lease fuel use during production and gathering in Oklahoma and Kansas and the flaring is marginal.

6. Appalachia to Northeast

The Appalachian Basin to Northeast supply chain flows (Figure 5-9) are defined at the border crossing from Pennsylvania to New York, Pennsylvania to New Jersey, and Pennsylvania to Delaware. The major pipelines that move gas production from Pennsylvania to demand centers in the upper Northeast for consumption include Columbia Gas (TCO), Eastern Gas Transmission, Eastern Shore, Millennium, National Fuel, Stagecoach, Tennessee Gas, TETCO, and Transco. For this evaluation, Northeast Pennsylvania was used for the Appalachia to Northeast supply chain. That supply chain produces dry, nonassociated gas, which does not require processing. Infield energy is estimated to be 3.5% of marketed production, which is based on EIA's estimate of lease fuel use in Pennsylvania, with marginal flaring.

Source: East Daley Analytics, 2023.

Figure 5-9. *Appalachian Basin to Northeast Supply Chain*

Increased production in Appalachia and proximity to the northeast market results in a lower-emissions supply chain through distribution. Using the supply in the Northeast reduces transportation emissions versus other longer route supply chains.

This availability of Appalachia natural gas has resulted in transition of fuel used for electricity generation in the Northeast and subsequent idling of some coal-fired plants in the region.

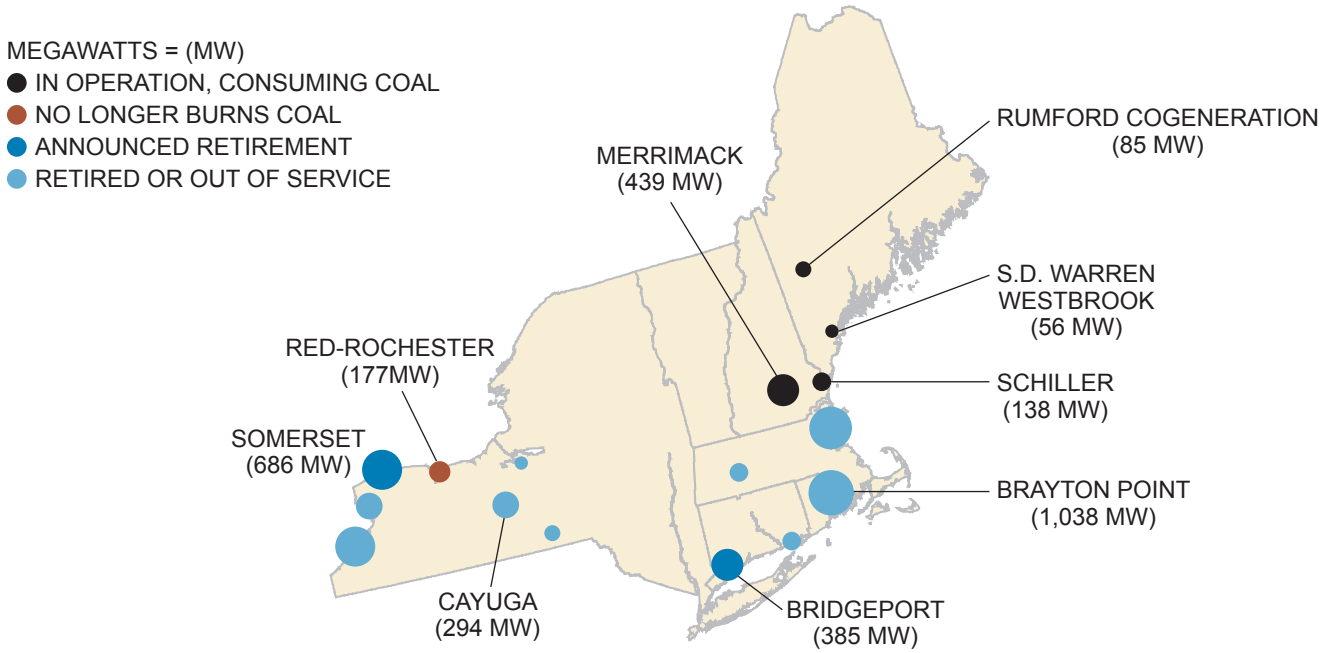
Figure 5-10 illustrates the advantages of natural gas and the transition in fuel for electrical generation.[9]

Coal-fired generation has fallen in the Northeast, shuttering several coal power plants. For example, retirement of New York Somerset (Figure 5-11) and Cayuga will account for approximately 980 MW of coal-generated electricity eliminated. Pipeline-quality natural gas production has increased over the past two decades, enabling electrical generation from gas to increase from 2% in 2001 to 52% in 2019 displacing most of the coal-fired generation in Pennsylvania.[10] In 2019, with the shuttering of a nuclear power plant, natural gas became Pennsylvania's largest source of in-state electrical generation.

The Appalachia to Northeast supply chains are characterized by high utilization and capacity constraints, with average utilization at 89% of available pipeline capacity. The ability of natural gas to continue to meet demand in the Northeast—particularly New York and New England—is limited due to continued and sustained opposition to new pipeline projects or the expansion of existing pipelines and the promotion of further idling of coal-fired electric generation in the region contribute to those limitations. For example, New York, which faces perennial winter shortages of natural gas and associated price spikes, has pursued several policies to prevent pipeline construction, relying in part on long-term plans to eliminate natural gas use for power generation.

9 EIA. "Coal-Fired Electricity Generation in New England and New York Has Diminished." February 4, 2020. https://www.eia.gov/todayinenergy/detail.php?id=42716.

10 EIA. "In the Past 20 Years, Natural Gas Has Displaced Most Coal-Fired Generation in Pennsylvania." January 26, 2023. https://www.eia.gov/todayinenergy/detail.php?id=55319.



Source: EIA, "Preliminary Monthly Electric Generator Inventory."

Figure 5-10. *Coal Plant Retirements*

Source: Copyright Jim Cavanaugh.

Figure 5-11. *Somerset Power Plant*

C. Supply Chain Modeling Results and Recommendations

Figure 5-12 summarizes the results of the SLiNG-GHG LNG model at the supply chain level. Details and explanation of the analysis are provided in Chapter 4. Several insights concerning the GHG emissions of CO_2 and CH_4 become apparent when considering the results at a supply chain level. Transmission of the produced natural gas becomes a significant contributor to GHG emissions. Emissions during transmission overtake all other sectors the farther the supply basin is from the end use.

The analysis estimated through Gate 2 (production through distribution) demonstrated that nonassociated dry gas production and shorter transportation pathways are the least CH_4-intensive supply chains. Appalachia to the Northeast and Haynesville to the Gulf Coast were the two least CH_4-intensive supply chains, with 0.10 and 0.11 g/MJ delivered, respectively. The analysis also showed that, when combined,

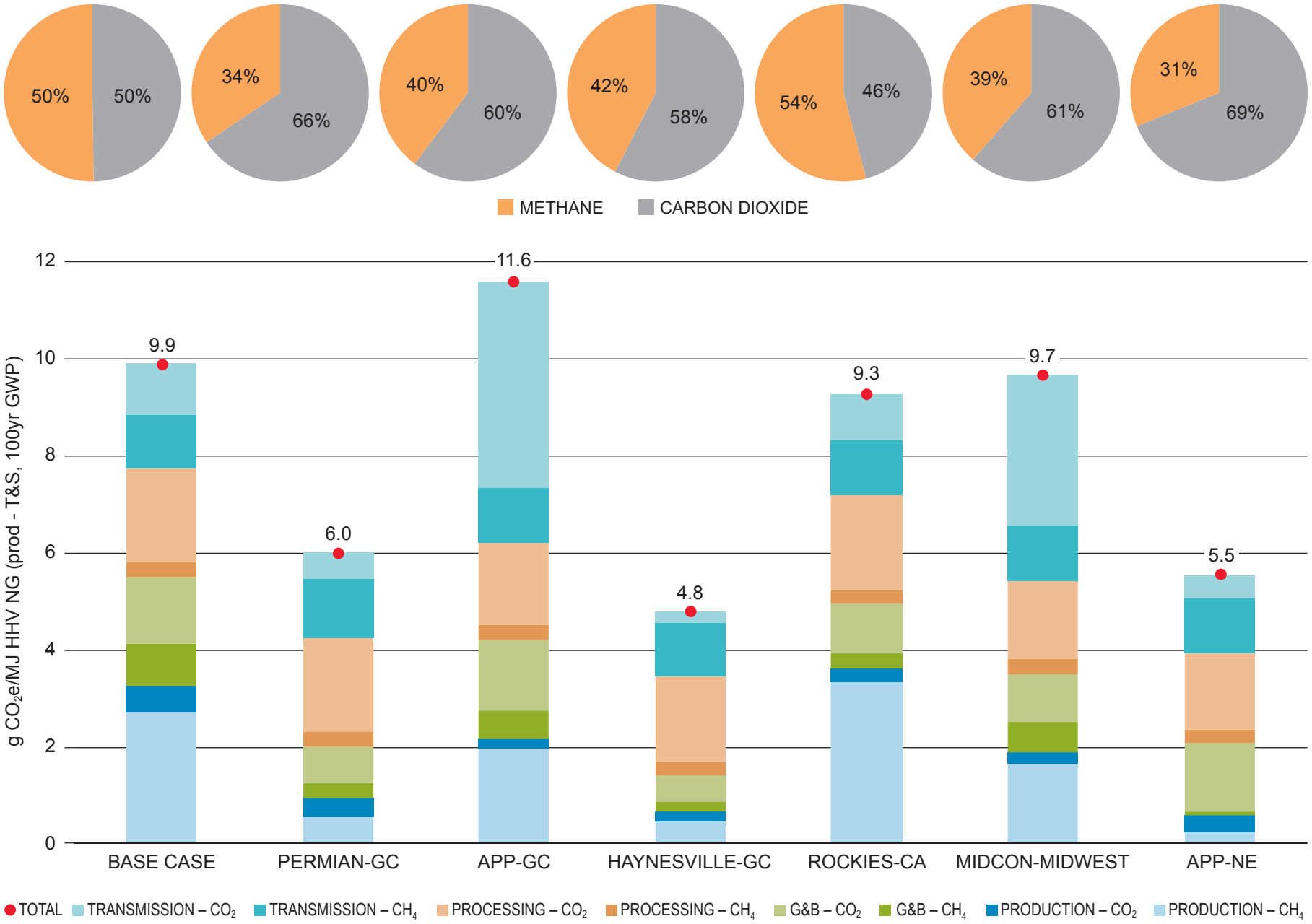


Figure 5-12. *SLiNG-GHG Model Results by Supply Chain*

Category	Equipment Type	Application	Supply Chain Applications
New Equipment	Methane sensing (quantitative capabilities)	Detect and repair methane leaks along the natural gas supply chain components	May be applicable to parts of or all supply chain components May be appliable to some or all producing basins
Established Technologies	Instrument air to run production equipment	Replace natural gas-driven pneumatic devices with instrument air to reduce methane emissions	May be applicable to parts of or all supply chain components May be appliable to some or all producing basins
Emerging Technologies	Methane measurement technologies	Fixed sites, ground vehicles, drones, high altitude platforms, aircraft, and satellites	May be applicable to parts of or all supply chain components May be appliable to some or all producing basins
	Methane Emissions Technology Evaluation Centers (METEC)	Ability to test emissions detection and quantification technologies	May be applicable to parts of or all supply chain components May be appliable to some or all producing basins Consider strategically adding new facilities within producing basins such as Bakken, Eagle Ford, Marcellus, Permian, and offshore

Table 5-2. *Emissions Abatement Actions*

these supply chains total approximately 59% of the entire pipeline-quality gas production of the six supply chains analyzed. However, the total of these supply chains represents approximately only 22% of the CO_2e intensity of the six supply chains analyzed as part of this study.

The study notes that there are other gas plays overlapping these states, and that some states contain multiple gas plays. For further details, please reference the supply chain key model inputs appendix in Chapter 4. Table 5-2 summarizes possible GHG emissions abatement options across natural gas supply chains as informed by supply chain modeling. Table 5-2 also provides examples of low-emissions equipment and technology deployment for which market mechanism actions would support investments.

Based on these supply chain case studies and modeling, multiple findings and recommendations were identified:

FINDING 1: **Supply chain data availability is limited and challenging to use to produce supply chain-specific GHG estimates. National databases containing information related to basin-level natural gas production are inconsistent in data representation and transparency across production segments.**

RECOMMENDATION 1: ***The NPC recommends the Energy Information Administration, National GHG Data Center, and other federal agencies provide supply chain-specific data and tools to enable tracking and reporting of GHG intensity at a supply chain level. This should be aligned and integrated with broader federal investment in remote sensing and data gathering, assessment, and reporting. To ensure data quality and functionality operators should ensure reported supply chain data are accurate.***

FINDING 2: **Natural gas supply chains have unique characteristics, resulting in differentiated GHG emissions intensity on a delivered basis.**

RECOMMENDATION 2: *The NPC recommends that, where natural gas GHG emissions intensity is reported or assessed—including for voluntary reporting, regulatory compliance, or for securing policy-driven incentives—the specific characteristics of natural gas supply chains be considered. This includes differentiating GHG emissions intensity on the basis of energy allocated GHG emissions by coproduct per basin, regional, and/or operator emissions performance where emissions reporting assurance can be provided.*

FINDING 3: To meet future regulatory requirements and to achieve incremental methane abatement goals, significant deployment of new equipment and components will be required across oil and gas supply chains. This deployment should include established technologies, as well as the further development of emerging technologies and new approaches to emissions abatement.

RECOMMENDATION 3: *The NPC recommends the federal government, state governments, and oil and gas industry bodies expand funding for research and development to scale up production and deployment of equipment and technology—including, but not limited to, engines/turbines, compressors, and pneumatic devices—to abate methane emissions, The DOE and Congress should direct existing and future funding and tax credits to these activities to support further innovation, production capacity scaling, and deployment of equipment and technology to abate methane emissions.*

FINDING 4: Investment in new and existing natural gas infrastructure can contribute to a net reduction in GHG emissions. This can include reductions in flaring and infield energy use for gas delivery to markets with lower GHG emissions intensity than alternative routes.

RECOMMENDATION 4: *The NPC recommends the federal government, state governments, and local governments act to reduce barriers for infrastructure development. This includes projects and activities that can directly reduce GHG emissions at different steps of natural gas supply chains, as well as infrastructure to deliver natural gas to market in shorter and more efficient supply chains. Development of additional infrastructure will require societal engagement and national and local permitting reform as discussed in Chapters 1 and 2.*

The recommendations on permitting made in the NPC's *Dynamic Delivery* report in 2019 also address infrastructure development barriers.[11]

D. Electrification of Compression: Analysis and Recommendations

Across this study, GHG emissions from energy use in natural gas compression has been consistently identified as a material driver of natural gas emissions intensity. In the assessment of supply chain case studies, it also stands out as a material driver of differentiated emissions intensity by supply chain. Specifically, those supply chains that are longer, and thus require greater compression, are higher in emissions intensity. Reducing GHG emissions from natural gas supply chains, therefore, will require significant scaling of different low-carbon technologies, including, but not limited to, electrification, energy efficiency, carbon capture and storage (CCS), and low carbon intensity (LCI) hydrogen.

One solution is the replacement of combustion-driven compression with electric-driven compression. This switch could lead to a significant reduction in emissions, particularly of CO_2. It is important to consider the additional challenges and consequences that come with replacing gas-fired drivers with electric-motor drives. For example, not only do electric drivers increase Scope 2 emissions when utilizing grid power, but their installation increases dependence on the

11 National Petroleum Council. "Dynamic Delivery: America's Evolving Oil and Natural Gas Transportation Infrastructure." 2019. https://dynamicdelivery.npc.org/.

power grid, thereby increasing risk and reducing resiliency.

1. Emissions Associated with Electric Compression

While in some areas of the United States, the Scope 2 emissions associated with electrical compression are less than the Scope 1 emissions from gas-fired compression, there are areas where the Scope 2 emissions are greater. There is not only a regional differentiation between the carbon intensity (CI) of grid electricity, but a temporal variation, depending on the overall load on the electricity grid. As electricity demand continues to increase due to a shift toward end-use electrification, the electric generation and transmission grid must expand to keep pace. This will have an impact on the actual Scope 2 emissions intensity resulting from electric compression and needs to be considered in site-specific evaluations.

2. Costs Associated with Electric Compression

While electrifying compression presents cost challenges to pipeline operators, it also directly impacts consumer rates. Generally, electricity costs more per megawatt of delivered energy than gas, and this additional cost is passed onto consumers. Several factors inflate the cost of electricity, including the need for additional infrastructure and the fact that electricity prices are exposed to demand surge pricing. Investing in more cost-effective methods of reducing GHG emissions intensity from the U.S. natural gas supply chain could protect the energy supply chain from a price increase feedback loop whereby greater electric demand for compression can increase peak load requirements and thus wholesale power prices at peak times. These increased costs can be partially offset by the lower operations and maintenance costs of electric compression when compared to gas-fired compression. These trade-off factors need to be considered in site-specific evaluations.

3. Reliability Concerns

Applying a strategy of electrification to reduce GHG emissions intensity from the natural gas supply chain has trade-offs that need to be evaluated. As natural gas continues to play an increasingly critical role in proving firming capacity to accompany variable energy sources in power generation, volatility in natural gas demand will continue to increase. Higher volatility requires natural gas supply chain operators to understand effects on reliability due to implementation of GHG emissions reduction actions, such as increasing the fleet of electric-motor drivers on natural gas compressors across gathering and transmission pipeline infrastructure.

Electrical outages at compressor stations with electric motor-driven compressor units will have a greater impact on the reliability and resiliency of the downstream supply chain than those occurring at compressor stations with natural gas engine drivers. Backup electric generation at compressor stations (with electric motor-driven compression) is not currently sized to provide backup power for operating compressor units. Instead, backup generation at the compression facilities is typically only sized to provide secondary power to ancillary and safety systems. Winter weather conditions are a leading cause of power outages and such outages at compressor stations with only electric motor-driven compressors can have significant consequences. This creates a potentially dangerous loop where the reliability of a compression facility (designed with electric-motor drivers to support emissions reduction targets) is most vulnerable during times when its reliability is most critical.

FINDING 5: **Little technical analysis has been performed on the potential reliability trade-offs of installing natural gas compressors with electric motor drivers versus natural gas-fired engine drivers.**

RECOMMENDATION 5: ***The NPC recommends further technical analysis be performed to better understand the potential reliability trade-offs of increasing the fleet of electric motor-driven compressor units across the natural gas supply chain for emissions reduction purposes.***

In the interim, there are certain steps that can be taken to bolster reliability. These steps may include more proactive gas-electric coordination between the two industries and designing compressor stations to have backup compression that

is natural gas driven. With respect to gas-electric market coordination, there are several initiatives currently being led by organizations such as the North American Energy Standards Board (NAESB), the National Association of Regulatory Utility Commissioners, the North American Electric Reliability Corporation, and regulators such as the Federal Energy Regulatory Commission (FERC). Natural gas infrastructure companies do and should continue to engage with these organizations, and others as applicable, to identify opportunities to continuously strengthen the reliability of the natural gas supply chain through enhanced coordination with the electrical industry. Additionally, natural gas facilities with electric motor-driven compression should proactively coordinate with their electric power providers so that the providers are informed of the critical service at the facilities to ensure prioritization of loads during periods of vulnerability. With respect to natural gas compressor stations having a mixture of compression driven by electricity and natural gas, regulators should consider reliability trade-off risk when favoring facilities with a design of only electric motor-driven compressors. They should instead consider mechanisms to promote a mixture of compression drivers to ensure reliability across the natural gas supply chain.

4. Security Concerns

The past decade has seen a rise in both physical and cyberattacks on critical infrastructure systems, including natural gas and electric transmission systems. Recent physical attacks on substations reveal a massive single point of failure within the electricity supply chain. Subjecting the natural gas supply chain to that same vulnerability without substantial improvements would be an oversight. Additionally, the more interconnected the two systems become due to electrification of compressor stations, the more vulnerable each is to physical and cyberattacks carried out on the other.

FINDING 6: Electrification of compressor stations could reduce Scope 1 emissions from natural gas compression. However, the trade-offs in this approach result in an increase in Scope 2 emissions (the degree of which is highly dependent on location) and has the potential to expose the energy supply chain to increased reliability risks. Operator collaboration with electric power providers, system operators, and oversight bodies can help address reliability risks.

RECOMMENDATION 6: *The NPC recommends that installation of electric drives be considered on a case-by-case basis alongside other cost-effective decarbonization strategies to ensure the delivery of clean, reliable energy. Furthermore, the NPC recommends the U.S. federal government coordinate policies and initiatives for low-carbon technology demonstration and deployment to maximize GHG emissions reductions within U.S. natural gas supply chains. This approach should balance electrification with reliability, security, and cost impacts against other decarbonization strategies. This includes but is not limited to deployment of carbon capture and storage in engine exhaust, hydrogen blending in driver fuel gas, and provision of low-carbon power for relevant gas supply chain steps.*

E. Analysis of Operator Actions to Reduce GHG Emissions in Natural Gas Supply Chains

Reducing GHG emissions within specific supply chains will require extensive action by oil and gas operators at all stages of natural gas supply chains. As operators develop and execute emissions reduction plans—for regulatory compliance, as well as to meet voluntary commitments—there are three critical areas of activity: (1) Operators will need to effectively plan; (2) Operator cooperation at a basin or regional level will be critical to deliver emissions reductions; and (3) More work will need to be done to understand emissions reduction options for orphan wells.

1. Operator Planning and Marginal Abatement Cost (MAC) Curves

There have been significant resources devoted through voluntary industry efforts (such as the

Environmental Partnership and the Environmental Protection Agency (EPA) Natural Gas STAR program) to understand abatement options, share case studies, and develop industry best practices to address methane and flaring emissions, as discussed in-depth in Chapter 1. The federal methane regulations that were discussed in Chapter 1 are a step toward codifying many of these best practices.

As Chapter 1 illustrates, the U.S. natural gas industry is on an ambitious methane emissions and flaring reduction path over the coming years. While the regulation development process is, for some stakeholders, an end point, resultant regulations are the beginning of a compliance process for the regulated community. Infrastructure to support flaring reductions, control technologies to reduce methane venting, measurement requirements for methane, and additional leak detection and repair (LDAR) programs are expected to require significant, multibillion-dollar investments across natural gas operators and dedicated resourcing of spending and capacity within companies to execute. Future regulations are expected to require significant reductions in inventoried methane and flaring emissions sources, which will also require the development and implementation of measurement-informed methane emissions inventory frameworks (Chapter 3).

With the reduction of methane emissions and flaring, GHG emissions associated with fuel combustion to power drilling, heating, and compression activities throughout the natural gas supply chain were modeled. Those GHG emissions are expected to grow as a percentage of overall emissions in the sector. Figure 1-39 in Chapter 1 depicts a higher percentage of carbon dioxide emissions compared to methane emissions in the sector for both the 2030 and 2050 pathways. Several companies are working to reduce these GHG emissions as part of state programs (e.g., California and Colorado), voluntary GHG emissions reduction programs, and energy efficiency improvement initiatives. However, compared to methane emissions sources and flaring, there has been less work to systemically analyze industry-wide carbon dioxide reduction opportunities.

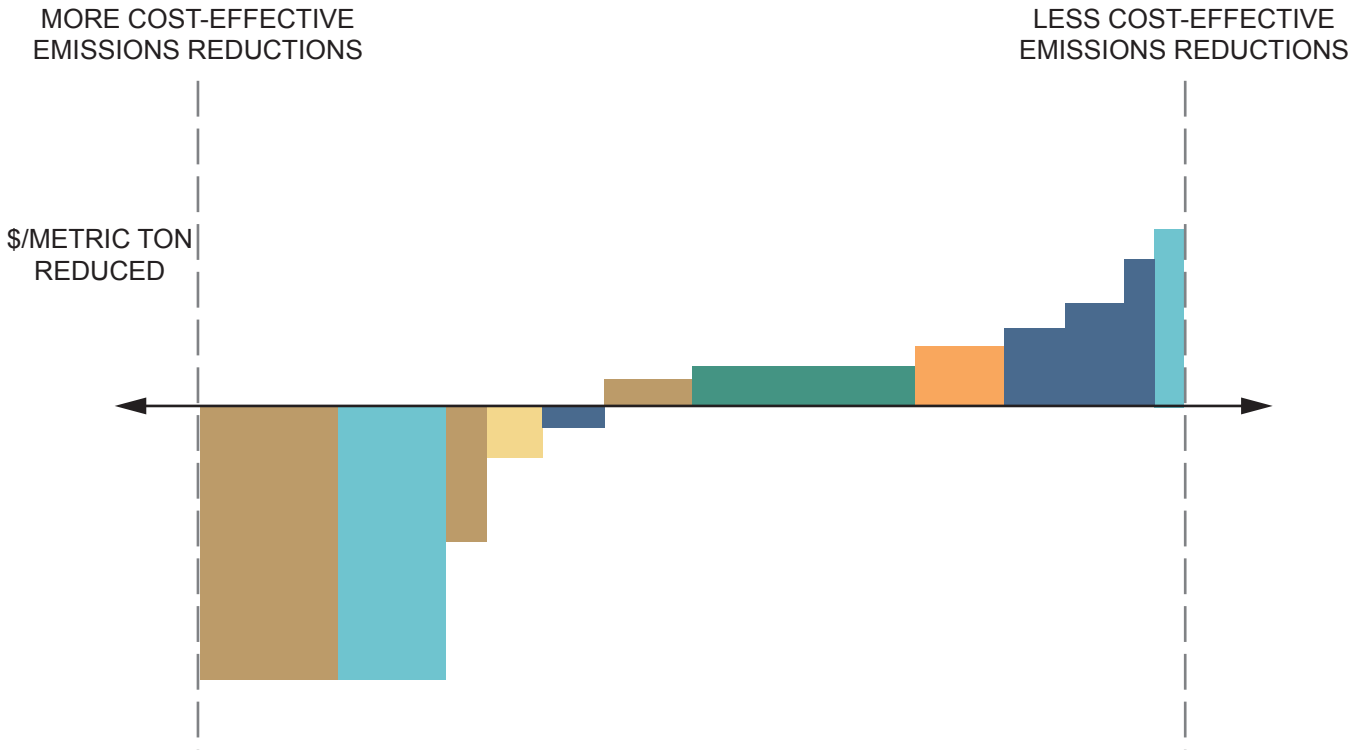
As discussed in Chapter 1, reducing GHG emissions associated with energy use will require continued technology development, the installation of infrastructure, and market signals to incentivize investments. Chapter 1 makes specific recommendations for establishing a new research, development, and deployment program within the DOE to focus on specific technology needs in this space. Alternative means of supplying lower CI compression, heat, and power will ultimately require new infrastructure that ranges from transmission lines to pipelines for CO_2 or H_2, that must be reliable in construction timelines and operation. This chapter provides an in-depth discussion of market mechanisms and their application to cost effectiveness of emissions reduction actions.

While companies within the oil and gas sector are focused on reducing methane emissions and flaring this decade, the industry should be planning for continued reductions in GHG intensity over the coming decades. One useful tool for this planning is marginal abatement cost (MAC) curve analysis.

MAC curves show the comparative cost effectiveness of different GHG abatement options. They are frequently used by companies to evaluate which GHG reductions to prioritize and can help policymakers understand the reduction costs of specific sectoral actions and the relative cost effectiveness of reducing emissions in one sector compared to another.

Figure 5-13 depicts an example of a MAC curve. Each bar represents a type of emissions reduction project. The colors indicate thematic emissions reduction opportunities (i.e., compression, flaring reduction).

The study team commissioned the Center for Energy Studies at Rice University's Baker Institute to evaluate the ability to assess marginal abatement costs on the six supply chains. After a literature review, the Center for Energy Studies determined that MAC curves reported in the literature are not sufficient representations of MAC. Rather, they are based on the cost of an abatement measure and an expected reduction in emissions associated with that measure, generally applied across the entirety of emissions at a specific source. The Rice University analysis focused on methane emissions, but the concepts are similarly applicable to carbon dioxide.



Source: Department of Commerce, "Methane Abatement for Oil & Gas—A Handbook for Policymakers," https://cldp.doc.gov/methaneabatement-resources.

Figure 5-13. *MAC Curve*

There are two necessary variables for abatement decisions: the cost and the expected emissions reduction. Ideally, resources will be allocated so the cost-per-unit emissions reduction is minimized. Interviews with operators that use MAC curves in their selection and prioritization of abatement projects indicated that they use project-specific emissions reduction and cost data, and then assemble those in decreasing merit order (higher cost per ton of reduction) to create their own MAC curves.

A review of the literature showed that the MAC curves in four widely referenced public- and private-sector estimates of abatement cost are not actual net marginal cost. Rather, they are indicators of a pseudo-average marginal cost associated with an expected reduction of methane emissions from a particular source, netted against a price assumption. Construction of a MAC curve in this manner results in an overstatement of emissions reductions that can be achieved at a particular cost.

The size of this error depends heavily on the shape of the marginal cost curve, which can only be understood with more rigorous measurement of emissions at multiple sources. Another very important detail is heterogeneity in and among natural gas supply chain operators. While macro-level assessments can be useful, if they fail to recognize differences across operators, then they will fail to identify differences in MACs across operators. In fact, it is simple to verify that operators with lower emissions (due to newer equipment, more rigorous maintenance, better operational protocols, etc.) will have higher marginal abatement costs than operators with higher levels of emissions. As such, blanket policies that impose specific industry-wide restrictions could unnecessarily penalize lower-emitting operators.

MAC curves are almost always presented as a net proposition, where the marginal abatement cost is netted against an assumed marginal revenue from selling, rather than losing, the methane that is abated. The price used to net this value is critical, as higher assumed prices will obviously lead to more robust positive economic outcomes. A blanket price assumption is inappropriate for evaluating the net MAC along a natural gas supply

chain because the price assumption must be consistent with the location of the expenditure to abate emissions. Some operators interviewed also noted that emissions upstream of a gas plant may include higher proportions of NGL with a different value than the methane emitted, adding variance to the net calculation. The fact that natural gas prices are different at various points in the supply chain is well known to anyone familiar with the industry.

MAC curves that use aggregated data are generally constructed in a way that does not adequately express true marginal cost. Using the result to determine overall abatement cost/benefits will result in suboptimal actions, because the cost/benefits for a specific firm, location, and component emissions will vary from the aggregated MAC curve.

FINDING 7: **Marginal abatement cost curves that use aggregated data are generally constructed in a way that does not adequately express true marginal cost. Using such marginal abatement cost curves to determine overall abatement costs and benefits will result in suboptimal actions because the costs and benefits for a specific firm and location and component emissions will vary from the aggregated marginal abatement cost curve. However, marginal abatement cost curves are a highly useful way for firms to determine their own prioritization and capital allocation for their own projects, where the emissions can be measured before and after, the capital cost can be determined for the specific project, and the gas value is site specific.**

2. Operator Collaboration and Best Practices

Operators have an important role to play in reducing emissions through collaboration with peers and the adoption of best practices. Each basin, unique supply chain, and asset carries with it specific emissions challenges and solutions. Operators have institutional expertise over their assets and are well positioned to determine the best design practices to mitigate their emissions. This section will consider several emissions reduction pathways described in Chapter 1 and examine how an operator may apply these general pathways to their asset group. Recognizing the diversity of regional and operational factors influencing emissions, this report also suggests operators join and contribute to industry trade groups with their peers for a pragmatic approach to emissions reduction.

The implementation of a LDAR program is focused on reducing the duration of fugitive emissions. As discussed in Chapters 1 and 3, there are several alternative detection technologies in development that could be used to replace regulatory LDAR compliance standards or voluntarily enhance an operator's existing program. Regional environmental and terrain differences can limit the options for effective technologies to consider. For instance, the mountainous terrain in the Marcellus Basin may not be suitable for continuous detection technologies that rely on line of sight or elevated wind speeds, while the flatter topography in the Permian Basin is well suited to those same technologies. Likewise, if a region commonly experiences high winds and overcast conditions, these conditions can influence the efficacy of aerial flyover technology. Operators are encouraged to collaborate with local peers and technology providers to determine which types of emissions detection solutions are the most effective for their specific operating area.

Variability of tank emissions is highly dependent on the characteristics of the hydrocarbons being produced or handled. In liquids-rich basins where natural gas production is primarily from associated gas, the liquids handling facilities are complex and therefore have a high leak potential. In these cases, additional equipment like vapor recovery units is required to capture and sell associated gas and reduce flaring or venting. As mentioned in Chapter 1, increased tank pressure ratings or tankless facility designs can improve vapor recovery unit operating conditions and reduce emissions. However, these complex design aspects may not be necessary for natural gas producers with relatively small quantities of liquids production. Facility design is dependent on the characteristics of the production and will

vary significantly between operators and basins. It is critical for operators to collaborate on the most effective and economic design solutions to handle their product while minimizing fugitive emissions and flaring.

Similar to tank emissions, increased emissions due to flaring during abnormal conditions is also primarily related to associated gas production. Efforts to centralize flaring to reduce the total amount of active flares can increase operations efficiency and require less equipment to manage, resulting in decreased emissions. This is most practical for upstream operators that also operate their own gathering and boosting segment. For example, one operator reported utilizing a flare management program that centralizes flaring of high-pressure gas during upset conditions to that operator's owned midstream locations where possible, reducing the high-pressure flare points and simplifying operations. This setup is not as feasible for midstream operators with multiple upstream partners due to the complexity associated with flaring gas downstream of a custody transfer point. It is encouraged for operators with integrated midstream systems to streamline and centralize upset flaring processes where possible. Additionally, it is recommended for midstream providers to consider business relationships with their upstream partners that could allow for the centralized flaring of gas during upset conditions. It is also critical for flares to operate at a high efficiency. Operators are encouraged to consider flare monitoring systems where practical. This may include more than monitoring the pilot temperature to ensure the flare is combusting as designed.

Finally, there are multiple region-dependent pathways for operators to emissions reductions associated with compression combustion. There are two emissions sources associated with engines on compressors: the carbon dioxide generated from the combustion process, and the methane slip in the exhaust stream resulting from incomplete combustion. Methane slip is especially a concern for compressors driven by lean-burn engines. As previously mentioned in Chapter 1, there is ongoing research on effective ways to reduce methane slip from these engine types, but solutions are not commercially available or scalable at this time. Electrification of the compressor engine would completely remove both sources but requires infrastructure that may not be available in all locations, adds complexities regarding grid reliability, and could be costly, especially for remote facilities. The overall emissions reduction impact of conversion to electric compression depends on the emissions intensity of the respective grid subregion and may provide opportunities for multioperator collaboration and codevelopment of electrification projects. Another option for emissions reduction, as explained elsewhere, is the use of compressors with rich-burn engines, which are designed to operate with a much lower methane slip rate than lean-burn engines. Each operator would need to consider the impact that installing rich-burn engines would have on nitrogen oxide emissions and strike a balance between GHG reduction and NOx emissions. Compressor availability can also vary between operating areas, and it may not be possible to source electric or rich-burn compressors at scale. Even when these units are available, it is costly to swap out existing compressors and may not be an efficient emissions reduction strategy compared to other pathways. Coordination between regional supply chain partners and vendors will facilitate the development of a compression strategy that overcomes the limitations and challenges posed by grid, asset, and environmental variables.

Industry trade groups may provide a platform to promote this kind of engagement and collaboration between operators. For example, the Environmental Partnership has organized measurement-based research of the emissions sources associated with compressors and facilitated discussions between operators and engine manufacturers. Chapter 1 also highlights several best practice sharing organizations. These groups foster productive discussions between operators and service providers, while protecting the privacy of members and upholding antitrust guidelines. It is highly recommended for operators to engage with their peers through vehicles like industry trade groups to build off the learnings of their peers while developing an emissions reduction strategy. Cooperation at this level can also help to address more systemic industry challenges (i.e., permits) and capitalize on opportunities (i.e., enhancing societal and community benefits).

All emissions reduction pathways in the natural gas supply chain, including those discussed above, require nonprescriptive solutions at the regional level. Operator collaboration on these complex issues, whether through trade groups or directly, is necessary to develop optimal solutions that reduce emissions across the supply chain. Such collaboration has the potential to exceed the outcomes that would result from meeting operator-specific, prescribed regulatory requirements alone.

FINDING 8: **Individual operator GHG emissions reductions actions and road maps are often unique, combining different practices and technologies depending on the specific regions or basins in which they operate. Industry trade groups can play a critical role in helping to drive such collaboration between operators.**

RECOMMENDATION 7: ***The NPC recommends that, as oil and gas operators develop plans to reduce GHG emissions, they develop emissions reduction options and assess trade-offs at a local asset level and in coordination with peer and downstream operators and technology vendors. While implementing these plans, they should seek to join and contribute to efforts at a regional or basin level to share best practices, collaborate on technology deployment, and enable wider industry participation and collaboration.***

3. Orphan Wells

The findings and recommendations in this study assume an operator for each element of a supply chain, such that an operator can act or be compelled by regulation to act to reduce GHG emissions. Orphan wells, which do not deliver oil or gas into a supply chain or have a known operator, thus require special treatment from a GHG emissions reduction standpoint. Known and/or viable orphan wells, as defined by the Interstate Oil and Gas Compact Commission and discussed in Chapter 1, are a subset of idle wells for which the operator is unknown or insolvent. Because orphan wells lack viable operators, they require unique solutions.

On federal land, orphan wells are managed by several agencies within the Department of the Interior (DOI) or the Department of Agriculture; on nonfederal lands they are managed by the relevant state regulator. Two primary concerns regarding orphan wells were identified in the study: (1) Keeping wells in operation while reducing their methane emissions would maintain the accountability of the operator, helping prevent the well from becoming an orphan; (2) If a well is determined to be an orphan, abandonment becomes subject to the agency's criteria for prioritization and availability of agency's limited resources. In many cases, the largest methane emitters will be addressed because states prioritize leaks of methane or other gases, although the impetus may be health and safety rather than climate. While data were of limited availability, anecdotally, the study team learned that the cost to states of documenting methane emissions, both before and after plug and abandon (P&A), can be onerous. Additionally, the study notes that funding sources for P&A orphan wells are diverse. Infrastructure Investment and Jobs Act (IIJA) funding has supplemented state plugging funds that are generally supported by fees and other assessments on operators. States require operators to post some financial assurance for P&A for wells subject to their regulatory jurisdiction.

The study team received several recommendations that operators should step in and voluntarily P&A wells that have been abandoned by other operators. The study found that the liability concerns of operators are an overarching factor in their opposition to voluntarily stepping in, and the requirements for legislative indemnification would likely be so high as to be unattainable. Therefore, this recommendation was rejected.

The study also learned that Tribal authorities have a similar concern regarding orphan wells on Tribal lands. Tribal authorities are equally reluctant as other operators to undertake P&A activities, especially if by doing so they take on liability arising from P&A activities that should have been completed by others.

Orphan wells located on Tribal lands require special attention, due to the responsibility at DOI

in overseeing management of lands held in trust or restricted status for Tribes or Nations and individual allottees. Orphan well P&A is further complicated by the complexity of the mineral management regulatory environment on Tribal lands. Three key concerns expressed by some stakeholders in the NPC study include:

- The DOI signed off on all the leases, and federal agencies (principally the Bureau of Indian Affairs (BIA) and the Bureau of Land Management (BLM)) have administered oil and gas development on these lands since inception. Those agencies have been inadequately staffed over the years. The DOI should understand that, unlike states, most Tribes do not have sufficient resources to determine what is needed to fully address P&A of orphan wells on their lands. The lack of organizational/technical resources in Tribes and the BIA have contributed to the fact that insufficient orphan well funding to date has gone to Tribes.
- For Tribes to choose to access federal dollars and manage P&A activity on orphan wells themselves, assurance must be provided that they will not take on additional liability (the "you touch it, you own it" concept). In the past, this concern has resulted in Tribes deciding to only identify orphan wells, not take on management activities. Once those wells are identified, P&A activities require cooperative involvement of either the state or the federal government to properly P&A those wells. That cooperative activity can be challenging depending on who has jurisdiction, which can be very complicated based on the checkerboarded nature of many reservation lands where oil and gas development has been historically undertaken.
- The study team received comments that federal bonding requirements have historically been inadequate, although BLM has proposed updates that are expected in 2024. The concern has been that a nationwide BIA bond (currently $150,000) does not provide a sufficient level of performance assurance regarding P&A obligations under leases covering Tribal lands. Some Tribes have created alternative pathways, such as evaluating risks and corresponding bonding levels during right-of-way renewals or new right-of-way grants that require Tribal consent.

FINDING 9: The study recognizes each state's need to prioritize plugging and abandonment of orphan wells according to each state's prioritization criteria that include, but are not limited to, methane. The Interstate Oil & Gas Compact Commission is demonstrating leadership in this through their Orphan Well Task Force. The Infrastructure Investment and Jobs Act does not require methane quantification on state or private lands; on federal lands, it allows estimation.

RECOMMENDATION 8: *The NPC recommends the grant process accelerate distribution of federal funds from Infrastructure Investment and Jobs Act to states for plug and abandon activity while retaining state primacy in the prioritization of wells to plug and abandon.*

There is no need to measure methane emissions at every well. Regarding quantification of methane emissions, for quality control purposes a sampling of plugged and abandoned orphan wells rather than each orphan well may suffice. The NPC recommends that DOE continue to work on reducing measurement costs to the states.

FINDING 10: The EPA/DOE Methane Emissions Reduction Program provides funding to monitor and mitigate methane emissions from the oil and gas sector.

FINDING 11: The Infrastructure Investment and Jobs Act (IIJA) has $4.7 billion in potential funding available. Again, the Interstate Oil & Gas Compact Commission has shown leadership on ways to leverage federal funding, with a resolution urging the Department of the Interior to allow combining of carbon credits income with federal funding. This could be a useful innovation, as it will increase focus on methane emissions reductions, allow private-sector money (from carbon credit sales) to supplement the overall plug and abandon budget, and require no new process in the grant process for IIJA plug and abandon funds.

RECOMMENDATION 9: *The NPC recommends operators evaluate the efficacy of current state programs for funding plug and abandon efforts, and where required, provide additional funding. Options that some stakeholders have suggested for consideration are: (a) changing regulations to allow insurance rather than bonding, with the beneficiary being the state budget, and allowing an increasing insurance premium as the well's reserves deplete toward zero; (b) using production as a trigger, compelling a supplemental royalty from low-producing wells into the state plug and abandon fund in lieu of bonding; and (c) requiring all operators to pay a supplemental production fee into the state plug and abandon budget (as is done in many states), which could be a flat fee per unit of production or could have a different payment level for marginal well producers. As with many complex topics, there are advantages and disadvantages of each listed approach and the behavior that it might incentivize; regulators and the regulated operators should collaborate on ways to improve state plug and abandon programs.*

FINDING 12: Orphan wells on Tribal land: The Department of the Interior should understand that unlike states, most Tribes don't have the resources to determine what is needed to fully address the orphan well issues on Tribal lands. The lack of organizational/technical resources in Tribes and federal agencies supporting Tribes has contributed to the fact that insufficient orphan well funding to date has gone to Tribes. Certain Tribes have operating entities that are the operators of record for their wells, and appropriately take plug and abandon responsibilities for those wells. However, this does not extend to orphan wells, notably for liability concerns.

RECOMMENDATION 10: *The NPC recommends that, in addition to providing adequate funding, the federal government also supply organizational/technical resources to Tribal governmental authorities or entities that are willing to address orphan well issues on their lands, including:*

1. *The Bureau of Indian Affairs needs to improve outreach and education on resources available to assist Tribes. Bureau of Indian Affairs needs to inform Tribes that funds are available and how to access them. Bureau of Indian Affairs should also consider requesting that organizations such as the National Congress of American Indians help inform and raise awareness.*
2. *DOE should assist the Bureau of Indian Affairs in the prioritization and categorization process for plug and abandon actions so that funding and field activities are prioritized. Liability for orphan wells previously operated by others should not be transferred to the Tribal entity.*
3. *DOE should provide coordinating resources to establish contact between plug and abandon contractors and Tribal authorities, similar to DOE's Carbon Matchmaker.*

RECOMMENDATION 11: *The NPC recommends that bonding requirements be commensurate with the risk and size of operator's operations on Tribal lands. The NPC further recommends creating an avenue to allow Tribes to work with the Department of the Interior to impose additional bonding requirements.*

FINDING 13: While the United States grapples with properly plugging and remediating approximately 92,000 documented orphan wells[12] and potentially hundreds of thousands of undocumented orphan wells, it is important to ensure that the approximately one million active wells in the United States are properly plugged and remediated by their operators at end of life and that state and federal oil and gas agencies are adequately funded by industry and state budgets to plug orphan wells that slip through the cracks. States have pursued reforms in recent years to strengthen financial assurance requirements, strengthen idle well management, increase well transfer oversight, and increase state orphan well

12 Interstate Oil and Gas Compact Commission. "Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies 2021." 2021. https://iogcc.ok.gov/sites/g/files/gmc836/f/iogcc_idle_and_orphan_wells_2021_final_web.pdf.

plug and abandon funds. The Infrastructure Investment and Jobs Act encourages this activity by providing states with incentives of up to $70 million each for enhancement to plugging rules; working on financial assurance, idle wells, and well transfer; and increasing in-state orphan well funding. There is no one right way to manage orphan wells programs—states have many tools to use based on their historical and current industries, geographic and geological factors, and related issues.

RECOMMENDATION 12: *The NPC recommends that states and federal land management agencies continue to work with the Interstate Oil & Gas Compact Commission to develop guidance for agencies looking to strengthen these policy tools.*

II. SCENARIO ANALYSIS

A. Role of Scenarios in Estimating Future Emissions Trajectories

Given that this study characterizes GHG emissions across all phases of the natural gas supply chain, understanding how that supply chain will evolve is critical. The evolution of GHG emissions depends on many factors related to the production, transportation, and consumption of natural gas. Particularly relevant is the evaluation of different regional characteristics in those supply chain steps, as well as the future.

To characterize GHG emissions from the U.S. natural gas supply chains, this study evaluated public, third-party energy scenarios to address the following questions:

- **Production.** What is the extent of U.S. natural gas production and where is that natural gas expected to be produced?
- **Transportation.** How is the geographic distribution of natural gas supply chains likely to change?
- **Consumption.** How is natural gas consumption likely to change geographically and across sectors?

This study addresses each of those questions, considering both the short term (2030) and the long term (2050). Future production, transportation, and consumption depends on various economic, technical, and policy outcomes that cannot be predicted today. Therefore, this report considers multiple future scenarios spanning different economic, technical, and policy outcomes. In this chapter, several scenarios are presented describing different potential levels of U.S. natural gas production, transportation, and consumption, including regional variations associated with each segment of the supply chain.

B. How Are Scenarios Used?

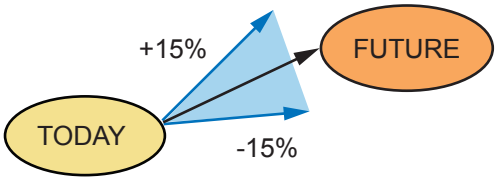
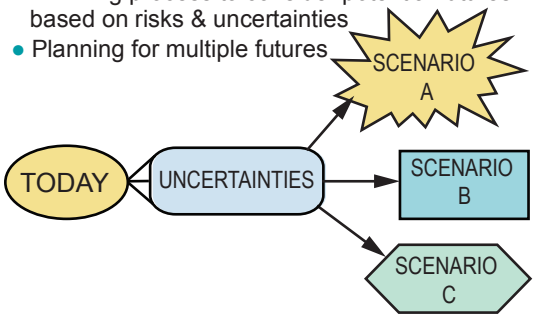
Forecasts are constructed by applying quantitative data and trends to predict one probable future scenario that an organization then uses as the basis of its plans. They are typically built using historical data or trends and are a shorter-term tool that provides guidance based on known variables in the system. Some of these variables are highly uncertain, and in some cases, models are used to predict their outcomes.

A scenario is a hypothetical construct that uses assumptions and estimates to highlight central elements of a possible future but is not a forecast, prediction, or sensitivity analysis. Businesses, governments, and other organizations use scenarios for planning purposes. Scenario planning is focused on the future and involves defining stories behind different paths that will lead to that future, a dynamic sequence of interactive events, casual processes, and critical decision points. It offers enhanced flexibility and preparedness to deal with risk and uncertainty instead of purely quantitative forecasting. Scenarios provide longer-term multiple futures based on unknown risks and uncertainties.[13] Modeling of long-term scenarios is inherently speculative, given the wide range of unpredictable variables and externalities that could affect outcomes through 2050.[14]

Figure 5-14 provides a more detailed contrast between scenario planning and forecasting,

13 Schwartz, Peter. *The Art of the Long View: Planning for the Future in an Uncertain World.* Currency Doubleday. 1996.

14 Mortlock, Lance. "Scenario Planning vs. Forecasting: 6 Questions to Ask to Prepare for a Post-Pandemic Future." LeadershipNow. May 12, 2021. https://www.leadershipnow.com/leadingblog/2021/05/scenario_planning_vs_forecasti.html.

	FORECASTING	SCENARIO PLANNING
PURPOSE	• Prediction of the future based on past historical information • Planning for one future 	• Thinking process to consider potential futures based on risks & uncertainties • Planning for multiple futures 
CERTAINTY	• Probable	• Plausible
INFORMATION TYPE	• Quantitative	• Qualitative & Quantitative
RISKS & UNCERTAINTIES	• Does not factor in risks and uncertainties, more about certainty	• Considers risks & uncertainties
TESTING	• Can be tested for accuracy	• Difficult to test for accuracy
THEORETICAL BASIS	• Based on a theoretical model • Future can be predicted	• Based on relationships and causality • Future is unpredictable
STAKEHOLDER ENGAGEMENT	• Narrow stakeholders involved in the process	• Wide set of stakeholders involved in the process from across the organization both internal and sometimes external
OBJECTIVITY	• Objective – fact based	• Subjective – guessing and assumptions
ACCOUNTABILITY	• Expert analysts, financial planners	• CEO, top level executives, CSO, facilitators and consultants
FREQUENCY	• Used daily	• Used every 2-3 years
HORIZON	• Short-term perspective	• Long-term perspective
REPEATABILITY	• Results can be replicated	• Involves unique representations

Source: LeadershipNow. https://www.leadershipnow.com/leadingblog/2021/05/scenario_planning_vs_forecasti.html.

Figure 5-14. *Forecasts and Scenario Planning*

comparing various features and explaining the differences.

The following section describes characteristics and assumptions of different third-party scenarios related to U.S. and global natural gas. The study team did not analyze the likelihood, precision, or accuracy of any scenario, outlook, or forecast, nor does it endorse the use of any particular scenario over others for planning purposes.

C. Sources of Future Energy Scenarios

Scenarios contemplating future production and consumption of energy are put together by different entities for different purposes. Example authors of energy scenarios include:

- Governmental and intergovernmental organizations, such as the EIA and the Organization of Petroleum Exporting Countries
- Government-sponsored research organizations, such as the International Energy Agency (IEA), the International Renewable Energy Agency, and the Intergovernmental Panel on Climate Change
- Private-sector organizations such as S&P Global, Wood MacKenzie, BloombergNEF, bp, Equinor, and ExxonMobil

Some scenarios are exploratory, meaning they consider how technical, economic, and political factors may influence energy supply and demand. Other scenarios are normative, meaning they show one a possible pathway to achieving a predetermined climate goal. Scenarios vary based on their assumptions regarding future changes in technology, policy, and economic conditions. Similarly, scenarios vary in the modeling construct and the granularity with which they consider production/consumption of different energy sources,

across different geographic regions, and times into the future.

The EIA released the Annual Energy Outlook 2023 (AEO2023), which combines the use of forecasts and scenarios to offer multiple possible futures for long-term energy trends in the United States. The AEO2023 includes a reference case and 12 side cases that explore key areas of uncertainty about how U.S. energy markets will develop. The 12 combination cases used in the AEO2023 utilized the National Energy Modeling System (NEMS) to expand capability to model a wider range of future scenarios. NEMS is a computer-based, energy-economy modeling system for the United States. NEMS projects the production, imports, conversion, consumption, and processing of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS is used by the EIA to project the impact that energy, economic, environmental, and security factors can have on the U.S. energy system because of alternative energy policies and different assumptions about energy markets. The projection period is about 30 years into the future.

Going forward, EIA has announced a substantial upgrade to NEMS, creating a next generation modeling framework that will more comprehensively address existing laws and regulations and will better model hydrogen, carbon capture, and other emerging technologies. This upgrade provides an opportunity to enhance the model in a manner that maximizes its potential as a planning and modeling tool to analyze opportunities to reduce GHG emissions across all energy systems.

FINDING 14: **Energy scenarios are critical for energy system planning. The most useful scenarios provide granular details about production and consumption within different regions of the country and sectors of the economy. Many organizations provide scenarios, but Energy Information Administration's scenarios are uniquely valuable due to their granularity.**

RECOMMENDATION 13: ***The NPC recommends that while the Energy Information Administration is updating the National Energy Modeling System, the functionality of the model should be enhanced to improve modeling and subsequent planning for the reduction of GHG emissions across locations and sectors for reducing GHG emissions across all energy systems. This can include functionality enhancements to enable the assessment of carbon dioxide and methane emissions from all energy systems across different scenarios, incorporating modeling of system resilience and enhanced integration with climate assessment models.***

D. Selection of Future Energy Scenarios

For the purposes of this study, the large number of organizations creating scenarios provides a useful perspective on the range and uncertainty in potential future outcomes. At times, even scenarios with similar assumptions can produce substantially different projections of future production. This study relies on granular assessment of natural gas production, transportation, and consumption in different regions of the United States. In contrast, some scenarios provide broad projections at the global or perhaps national level, lacking the regional granularity or the focus on the emissions intensity of the natural gas supply chain needed for this study.

In this study, projections of short-term and long-term regionally dependent U.S. natural gas production and consumption rely primarily on scenarios developed by the EIA and published in the AEO2023. The AEO2023 cases are rigorous, based on detailed understanding of the economical, technical, and policy environment in the United States. They are up to date, reflecting recent policies such as the Inflation Reduction Act (IRA); however, EIA acknowledges shortcomings that are discussed further in the subsequent section. Moreover, EIA considers a range of scenarios reflecting possible economic, supply, and demand environments, providing a robust assessment of future possibilities. Finally, the EIA scenarios uniquely provide granular detail regarding regional dependences within the United States as required for this study.

1. Energy Information Administration (EIA) Scenarios

For the reasons described above, the study focuses on EIA scenarios for this analysis. Four EIA scenarios were selected to establish a range of uncertainty on the natural gas supply chain in this analysis:

- **Reference**: The EIA Reference case, which should be considered the experimental control assuming nominal conditions. This scenario includes policies set forth in the IRA but includes no new policies or laws after November 2022. This scenario assumes evolutionary technological growth and sunsetting of policies with prescribed end dates.
- **High Supply**: In this scenario, the nation's endowment of hydrocarbons is relatively high. Compared to the Reference case, this case assumes a 50% increase in oil and gas recovery, 50% increase in undiscovered resources, and 50% increase in technology performance.
- **Low Supply**: In this scenario, the nation's endowment of hydrocarbons is relatively low. Compared to the Reference case, this case assumes a 50% decrease in oil and gas recovery, 50% decrease in undiscovered resources, and 50% decrease in technology performance.
- **Combined Low Macroeconomic Growth and Low Zero-Carbon Technology Costs (Low Macro Low ZCTC)**: In this scenario, two effects are modeled. First, U.S. GDP is assumed to grow at 1.4% annually (compared to 1.9% in the Reference case). Second, the cost of zero-carbon technologies—including nuclear energy, renewable energy, and diurnal storage—are assumed to be 40% lower by 2050 compared to the Reference case. While this is not a net zero case, it has elements that would arise due to favorable low-carbon policies.

One reason these scenarios were selected is to span a broad range of potential outcomes. Of all the EIA cases, the High Supply case finds the highest U.S. natural gas production in 2050 and the Low Supply case finds the lowest. EIA acknowledges that this range of four cases may not be sufficiently wide. EIA's narrative states that they are "working to incorporate novel fuel and technology pathways into the NEMS and to appropriately treat uncertainty around technologies with limited commercial deployment."

In this regard, the study notes two primary sources of additional uncertainty with respect to the EIA's analysis. First, the EIA's assumption with respect to heat pump and other electrical appliance costs remains either unspecified or relatively static through the outlook. Additionally, EIA notes that they do not explicitly model residential clean energy technologies. As such, natural gas-fired heating equipment, including furnaces and boilers, continue to account for the largest share of energy consumption for space heating in U.S. residential and commercial buildings across all cases through 2050. Should EIA further improve modeling in this area, it may change modeled results.

Second, EIA currently lacks a hydrogen module, and the organization is planning to incorporate this module into the enhanced version of NEMS. When EIA adds this module, it may also change the modeled results.

This section presents the results of the EIA scenarios. Included here are numbers for gas production by region of the country, gas consumption by region of the country, and gas consumption by sector of the economy in the short term (2030) and the long term (2050) and under all four EIA scenarios listed previously.

a. Gas Production by Region

Total Dry Gas Production is the volume of natural gas remaining after natural gas liquids have been removed. It does not include the volume of natural gas used to repressurize wells or what is vented or flared during the production or processing. Table 5-3 is a summary of the Total Dry Gas Production modeled by the EIA under the selected cases by region in 2030. The Reference and Low Macro Low ZCTC cases are similar in the total modeled dry gas production, including when looking at the contribution by region. In all four cases, the East and Gulf Coast are the biggest contributors, supplying 57%-63% of the volumes. The next largest contributors are the Southwest and Rocky Mountain regions, with each contributing 25%-30% of the total. Between the cases, the overall volume impact is reflected proportionally among

EIA Data—TCF	Reference	High Supply	Low Supply	Low Macro Low ZCTC
	36.7	39.3	29.4	35.2
By Region:				
East	13.1	13.2	11.5	12.5
Gulf Coast	9.2	9.3	7.1	8.7
Midcontinent	2.4	2.6	2.1	2.3
Southwest	6.0	7.7	3.7	6.0
Rocky Mountain	3.7	3.9	3.5	3.6
Northern Great Plains	0.8	1.1	0.6	0.8
West Coast	0.1	0.1	0.1	0.1
Lower 48 Offshore	1.3	1.5	0.8	1.3

Source: EIA, 2023, "Annual Energy Outlook."

Table 5-3. *2030 Total Dry Gas Production*

EIA Data—TCF	Reference	High Supply	Low Supply	Low Macro Low ZCTC
	41.7	49.3	29.0	38.0
By Region:				
East	15.5	16.1	12.9	13.4
Gulf Coast	11.0	13.4	6.9	9.9
Midcontinent	2.1	3.1	1.3	1.9
Southwest	7.4	9.3	4.4	7.3
Rocky Mountain	3.4	4.0	2.3	3.3
Northern Great Plains	0.8	1.0	0.4	0.8
West Coast	0.0	0.0	0.0	0.0
Lower 48 Offshore	1.4	2.5	0.8	1.3

Source: EIA, 2023, "Annual Energy Outlook."

Table 5-4. *2050 Total Dry Gas Production*

the regions, meaning no single region is impacted in comparison to the others across scenarios.

Table 5-4 is a summary of the Total Dry Gas Production modeled by the EIA and IEA under the selected cases by region in 2050. The East and Gulf Coast regions continue to be the largest producers, with the share increasing to 60-68% of production. The Southwest region's proportional contribution remains similar to 2030. However, the proportional shares of the Rocky Mountains and Midcontinent regions begin to decrease. In the Low Supply case, the production from the East region is proportionally much larger when compared to that region in the other cases; this case also shows all other regions declining except for the Rocky Mountain.

Comparing the 2030 dry gas production in Table 5-3 to the 2050 dry gas production in Table 5-4, the overall production volumes increase by 14% in the Reference case and 25% in the High Supply case. They decrease by 2% in the Low Supply case and increase by 8% in the Low Macro Low ZCTC case. In the Reference case, from 2030 to 2050, the volumes increase by 18%-23% in the East, Gulf Coast and Southwest regions, and decrease below 2030 levels in the Midcontinent, Rocky Mountain, Northern Great Plains, and West Coast regions. In the High Supply case, all the producing regions increase volumes from 2030 to 2050 except for in the Northern Great Plains and the West Coast. In the Low Supply case, all the producing regions decrease in volume from 2030 to 2050, except for the East and Southwest regions, which grow by 13% and 17%, respectively. In the Low Macro Low ZCTC case, a similar pattern to the Reference case is observed where volumes grow from 2030 to 2050 in the East, Gulf Coast and Southwest regions.

Some overall trends emerge from the scenarios shown in Tables 5-3 and 5-4. In the EIA Reference scenario, U.S. natural gas production grows steadily through the end of the modeled period (2050). Different EIA scenarios present a range of potential production volumes, although that range is somewhat narrow. In the High Supply case and the Low Supply case—the EIA cases with the largest deviation from the Reference case—production in 2050 varies by only 30% from Reference. This relatively small range across scenarios with widely different assumptions demonstrates the crucial role natural gas will play in the U.S. economy. Under existing policy as modeled by the EIA, there is effectively no low gas scenario, and gas will provide an irreplaceable source of energy for the coming decades, as found in all cases. Moreover, scenarios that may be expected to lead to low gas production end up with only modest production declines. The Low Macro Low ZCTC case includes two factors, each of which

results in reduced gas production. These are low macroeconomic growth, which reduces demand for all energy sources, and low zero-carbon technology costs, which encourage substitution away from natural gas toward renewable energy sources. Those combined effects result in only a 10% drop in U.S. gas production compared to the Reference case, which is smaller than the 30% drop envisaged in the Low Supply case. These results suggest that, under existing policy, macroeconomic factors, as well as renewable energy sources, have relatively modest impact in gas production.

End-use consumption includes all the natural gas volumes used by the Residential, Commercial, Industrial, Power and Transportation sectors. It does not include volumes consumed at the lease level or plant level. Table 5-5 shows the end-use consumption for all sectors by region across the four selected cases. Across all cases, the largest demand centers are the West South Central, East North Central, Middle Atlantic, and South Atlantic regions. The proportionate share of demand across regions remains relatively consistent across all four cases in 2030.

EIA Data—TCF	Reference	High Supply	Low Supply	Low Macro Low ZCTC
2030 End-Use Consumption – All Sectors	**25.0**	**26.7**	**20.0**	**23.5**
By Region:				
New England	0.7	0.7	0.6	0.7
Middle Atlantic	3.3	3.4	2.6	3.2
East North Central	4.4	4.6	3.6	4.2
West North Central	1.7	1.8	1.6	1.7
South Atlantic	3.1	3.4	2.3	2.9
East South Central	1.5	1.7	1.1	1.3
West South Central	6.1	6.7	4.7	5.6
Mountain	1.4	1.6	1.2	1.3
Pacific	2.8	2.9	2.4	2.6

Source: EIA, 2023, "Annual Energy Outlook."

Table 5-5. *2030 End-Use Consumption Across All Sectors by Region*

EIA Data—TCF	Reference	High Supply	Low Supply	Low Macro Low ZCTC
2030 End-Use Consumption – All Sectors	**26.1**	**30.7**	**21.2**	**21.4**
By Region:				
New England	0.7	0.7	0.7	0.6
Middle Atlantic	3.2	3.6	2.5	2.6
East North Central	4.6	5.5	3.6	3.8
West North Central	1.9	2.1	1.7	1.7
South Atlantic	3.1	3.8	2.2	2.2
East South Central	1.5	2.0	1.2	1.1
West South Central	6.6	7.9	5.2	5.2
Mountain	1.8	2.1	1.4	1.4
Pacific	2.8	3.0	2.7	2.6

Source: EIA, 2023, "Annual Energy Outlook."

Table 5-6. *2050 End-Use Consumption Across All Sectors by Region*

Table 5-6 shows the end-use consumption for all sectors in 2050 across the regions. Across all cases, the largest demand centers, for the most part, continue to be the West South Central, East North Central, Middle Atlantic and South Atlantic regions. The proportionate share of demand across regions also remains relatively consistent across all four cases in 2050.

Comparing the 2030 end-use consumption in Table 5-5 to the 2050 end-use consumption in Table 5-6 reveals that the overall consumption volumes increase by 5% in the Reference case, 15% in the High Supply case and 6% in the Low Supply case. Those volumes decrease by 9% in the Low Macro Low ZCTC case. In all cases, the largest and most sustained growth is seen in the Mountain region, while all other regions show different regional impacts among the four cases. The High Supply case shows sustained growth in all regions. The Low Supply case grows, but by a smaller amount, in all regions except for the Middle Atlantic and South Atlantic, in which overall consumption volumes decrease. The Low Macro Low ZCTC case shows the largest variability of the cases, with low relative growth in the West

North Central, Mountain, and Pacific regions and all other regions decreasing in demand from 2030.

Consumption by sectors in Table 5-7 and 5-8 reflect the same data as in Table 5-5 and 5-6 but is nationwide and delineated by consumption sector. Table 5-7 shows the end-use consumption for the entire United States by sector in 2030. Across all four cases, the largest end-use sector is Industrial, with 36%-39% of the overall consumption. In all cases, except for the Low Supply case, the ranking order of end use by sector remains consistent, with Industrial being the largest consumer, followed by Electric Power, Residential, Commercial, and Transportation. In the Low Supply case, Residential overtakes Electric Power as being the second-largest end use after Industrial.

Table 5-8 shows the end-use consumption for the entire United States by sector in 2050. Across all four cases, the largest end-use sector continues to be Industrial, contributing 38%-43% of the end use. The Reference and High Supply cases continue to have a consistent ranking order of end use by sector, with Industrial being the largest consumer, followed by Electric Power, Residential, Commercial, and Transportation. The Low Supply case continues to have Residential consumption higher than Electric Power. Similarly, the Low Macro Low ZCTC case shows Residential end use overtaking Electric Power by 2050.

EIA Data—TCF	Reference	High Supply	Low Supply	Low Macro Low ZCTC
2030 End Use by Sector	**25.0**	**26.7**	**20.0**	**23.5**
By Region:				
Residential	4.8	4.8	4.7	4.8
Commercial	3.5	3.5	3.3	3.5
Industrial	8.8	9.3	7.8	8.4
Electric Power	7.7	8.9	4.1	6.6
Transportation	0.1	0.1	0.1	0.1

Source: EIA, 2023, "Annual Energy Outlook."

Table 5-7. *2030 End-Use Consumption by Sector*

EIA Data—TCF	Reference	High Supply	Low Supply	Low Macro Low ZCTC
2050 End Use by Sector	**26.1**	**30.7**	**21.2**	**21.4**
By Region:				
Residential	4.7	4.7	4.6	4.6
Commercial	3.4	3.5	3.3	3.5
Industrial	10.0	11.5	9.1	9.1
Electric Power	7.7	10.6	4.0	3.9
Transportation	0.3	0.3	0.3	0.3

Source: EIA, 2023, "Annual Energy Outlook."

Table 5-8. *2050 End-Use Consumption by Sector*

Comparing the 2030 end use by sector in Table 5-7 to the 2050 end use by sector in Table 5-8 reveals that the Industrial and Transportation sectors are the only sectors consistently growing between 2030 and 2050 across all four cases. The Residential sector decreased while the Commercial sector stayed relatively consistent between 2030 and 2050 across all four cases. Electric Power appears the most impacted by the cases between 2030 and 2050, with the Reference case showing no growth in the 20 years, the High Supply case showing 19% growth, the Low Supply case reflecting a 2% decrease and the Low Macro Low ZCTC showing a 41% decrease in consumption over the period.

When looking at the data across Tables 5-3 to 5-8 and focusing on each specific case, the Reference and High Supply case both reflect a growth in consumption and end use to correspond with an increase in dry gas production. The additional production not consumed in the United States is exported either by pipeline or as LNG. The Low Supply case reflects a decrease in production from 2030 to 2050. However, the overall end-use consumption still grows during this period, which reduces the volumes available for export by 25%. In the Low Macro Low ZCTC case, the production still increases over the period, but end-use consumption decreases. This finding indicates that the assumed low-carbon technology development is likely more focused on the consumers, and this allows for additional exports.

	Reference	Low LNG Price	High LNG Price	Fast Builds Plus High LNG Price
Liquefied natural gas (LNG) exports (Bcf/d)	27.3	15.3	39.9	48.2
Henry Hub spot price (2022$/MMBtu)	$3.77	$3.28	$4.31	$4.81
Overall natural gas consumption (Bcf/d)	82.2	82.5	81.9	81.7
Industrial natural gas consumption, excluding lease and plant fuel (Bcf/d)	27.3	27.4	26.9	26.7
Electric Power natural gas consumption (Bcf/d)	21.2	22.8	19.7	18.6

Source: EIA, 2023, "Annual Energy Outlook."

Table 5-9. *Summary of Selected EIA Results*

2. LNG in EIA Scenarios

LNG received global attention with the Russian invasion of Ukraine and the subsequent disruption in the transmission of Russian natural gas via pipeline to European countries. The United States, as the world's largest natural gas producer, was able to quickly respond and became the world's largest LNG exporter in 2022. Increased exports to Asia, especially to Japan, also occurred. Japan sees LNG as necessary for the country's energy security and to help offset growing strategic competition with Europe over LNG imports. Additionally, Japan's government policy reflects the view that greater access to U.S. LNG will help reverse increased consumption trends of greater GHG-intensive energy sources—such as coal—in parts of the Indo-Pacific.

The high demand for LNG would allow the United States to remain a net exporter of petroleum products and natural gas through 2050 in all cases noted in the EIA *Annual Energy Outlook 2023* (AEO2023).[15] The AEO2023 also found that total natural gas exports, by pipeline or as LNG, would become larger than any domestic end-use sector, including Residential, Commercial, Industrial, and Electric power, by the early 2030s. Additionally, it found that total natural gas exports would become the largest component of U.S. natural gas demand in that time period. In the Reference case, the AEO2023 modeled that U.S. natural gas production would increase by 15% (42.1 trillion cubic feet (Tcf)), and LNG exports would increase by 152% (approximately 10 Tcf) by 2050.

In a May 23, 2023 update, the EIA analysis evaluated three additional cases: 1) Low International (Europe and Asia) LNG Price (Low LNG Price case), 2) High International (Europe and Asia) LNG Price (High LNG Price case), and 3) High International LNG Price plus Fast Build, i.e., faster development of export facilities (Fast Builds Plus High LNG Price case), to evaluate the potential impact on domestic natural gas prices and consumption by 2050.[16]

The NEMS model assumes a relationship between international LNG prices and Henry Hub prices. In the EIA cases evaluated here, international LNG prices are assumed to be 20% lower or 25% higher than the reference values. The results of these new cases indicated that LNG export prices increased domestic natural gas prices, which in turn decreased consumption rates by the two largest end users—Industrial and Electric Power (Table 5-9). However, the resulting variation in natural gas prices was narrower than what was seen in the March 2023 AEO. The decrease in natural gas consumed by the Electric

15 EIA. "Annual Energy Outlook 2023." March 16, 2023. https://www.eia.gov/outlooks/aeo/.

16 EIA. "Annual Energy Outlook 2023." March 16, 2023. https://www.eia.gov/outlooks/aeo/.

Power sector was more significant than the Industrial sector, as the current dispatch order favors the lowest priced electricity. Impacts on LNG exports, however, increased under both the High LNG Price and Fast Builds Plus High LNG Price cases.

3. Net Zero Scenarios

One difference between scenarios developed by EIA and scenarios developed by other organizations is that EIA focuses on existing policies, while other organizations contemplate future policy change. The United States has set an economy-wide net zero emissions target by 2050, but policy changes will be needed to achieve that target. The EIA does not speculate what those policies might be and does not provide a scenario aligned with that target. Therefore, in addition to the scenarios developed by the EIA, this report considered the use of other scenarios that contemplate a net zero trajectory. While many net zero scenarios are available, few provide projections at the level of granularity found in the EIA scenarios. This outcome is understandable, considering the uncertainty associated with projecting future policy changes.

A variety of domestic and international governmental agencies, companies, NGO organizations, and not-for-profit research institutions have developed net zero (NZE) scenarios. The recent NZE scenarios are normative scenarios that explore theoretical ways to achieve Net Zero by 2050. A nonexhaustive list of sources of NZE scenarios includes:

- IEA's World Energy Outlook
- Bloomberg New Energy Finance's New Energy Outlook
- Wood Mackenzie
- Multiple scenarios from different oil and gas companies

In addition, a report[17] compiled by Resources for the Future, summarizes scenarios created by a number of institutions.

Among scenario-producing bodies, specific attention has often been paid to the IEA. For an alternative perspective, the IEA Stated Policies scenario (STEPS) and Announced Policies scenario (APS) show declines by 2050 in the U.S. natural gas supply. In addition to STEPS and APS, the IEA has a global net zero scenario (net zero emissions or NZE) in which global gas demand is assumed to decline by 78% from 2022 to 2050. The IEA NZE scenario is representative of several other scenarios that seek to limit warming to a threshold, more so than policy current prescribes. While they are useful at a global level, most do not address supply or demand from a specific country like the United States. IEA does not project U.S. supply or demand within that scenario, and one cannot simply extrapolate from IEA's APS and STEPS global-country level data to NZE. IEA suggests that in these scenarios, the natural gas that meets the remaining demand will be the low GHG emissions natural gas. Regardless of natural gas demand, this study provides recommendations on actions to provide lower GHG emissions natural gas to the domestic and global market. The study team did not analyze the likelihood, precision, or accuracy of any scenario, outlook, or forecast, nor does it endorse the use of any scenario over others.

FINDING 15: **Energy Information Administration scenarios presently consider only current policies, limiting the range of future energy system plans. They also do not estimate methane emissions or model how those emissions would change under future scenarios.**

RECOMMENDATION 14: ***The NPC recommends the Energy Information Administration seek to provide a platform for more widespread third-party modeling of future energy and climate scenarios, including those contemplating changes in future policies that impact GHG emissions. This can include the development of an independent research platform to facilitate the comparison of different net zero and other low GHG emissions scenarios.***

17 Raimi, D., Zhu, Y., Newell, R.G., Prest, B.C., Bergman, A. "Global Energy Outlook 2023: Sowing the Seeds of an Energy Transition." *Resources for the Future.* March 28, 2023. https://www.rff.org/publications/reports/global-energy-outlook-2023/.

III. CHARTING THE COURSE

Across this study, more than 50 individual recommendations have been identified. These recommendations are in support of reducing GHG emissions from natural gas supply chains in a manner that incorporates societal and community engagement. Individually, these recommendations are discrete actions that can be taken by policymakers, industry, or civil society. Collectively, they represent a holistic path forward for the U.S. natural gas industry to reduce emissions while continuing to deliver the economic, social, and environmental benefits that natural gas can provide. The collective approach recommended by this study is not the only path forward. It is recognized that a selected range of measures could be combined to minimize GHG emissions from natural gas supply chains while balancing the factors described in the Secretary of Energy's study request letter.

Recommendations in this study draw on a common toolkit for reducing GHG emissions, including the use of government policy (at federal, state, and local levels), the advancement of technology, and industry action and coordination. Across these recommendations, several cross-cutting themes stand out:

- **Economics and creating incentives:** Throughout the report, the economic impacts of natural gas supply chains are discussed in both producing and consuming states, as well as from exports. While market incentives are in place to drive gas production and infrastructure investment, they are largely lacking to drive greater investment in GHG emissions mitigation. Thus, multiple findings and recommendations focus on generating incentives for investment in the reduction of GHG emissions from natural gas supply chains.
- **Regulation:** Multiple recommendations in this report focus on enhancing and enabling the successful implementation of methane regulations. This includes multiple recommendations that are aimed at incorporating economic considerations into the design and implementation of regulation. As outlined in the "U.S. Methane Emissions Reduction Action Plan" in 2021,[18] there are a wide range of regulatory measures being implemented, including updated EPA rules for methane from new and existing oil and gas sources, updated flaring and venting rules, rules for methane calculation methodologies, waste prevention rules on federal leases, and rules for midstream operators. Certain states have moved in advance of the EPA, adding to operators' challenge in complying with both sets of regulators. Harmonizing these regulations and enabling successful implementation at the state level will be critical toward driving down GHG emissions in natural gas supply chains.
- **Creating and expanding government programs:** The report recommends creating and expanding federal government programs across several categories, including technology demonstration, development of gas certification programs and to facilitate greater knowledge sharing and collaboration in the industry.
- **Geopolitics and international coordination:** Given the leading role the United States has taken in global LNG supply, multiple findings and recommendations focus on coordinating internationally and enhancing global energy security. These include engagement through multilateral institutions, as well as directly with U.S. trade partners.
- **Societal and community engagement:** As a top-line focus of this study, multiple findings and recommendations focus on enhancing societal and community engagement. These high-level themes, including public awareness; stakeholder involvement in policy development; transparency in reporting; capacity building; avoiding or mitigating adverse impacts on communities, particularly including local impacts in disadvantaged communities; and maximizing the effectiveness of community benefits that can flow from GHG emissions reduction projects.
- **Technology advancement:** Multiple findings and recommendations emphasize the role

18 The White House Office of Domestic Climate Policy. "U.S. Methane Emissions Reduction Action Plan." November 2021. https://www.whitehouse.gov/wp-content/uploads/2021/11/US-Methane-Emissions-Reduction-Action-Plan-1.pdf.

of technology in further advancing emissions reduction. This will require technology research, development demonstration, and deployment covering both emissions detection and quantification technologies, as well as abatement technologies.

- **Industry cooperation**: Industry efforts to support corporate commitments and voluntary initiatives are highlighted throughout the study. These pledges and initiatives often lead to the development of internal governance structures that exceed basic regulatory requirements, driving broader industry improvements. Furthermore, opportunities are identified for greater industry cooperation to share best practices.
- **Additional operator actions**: Deeper emissions reduction scenarios from gas supply chains will require technological developments and implementation by operators throughout the supply chain. As a result, some findings and recommendations focus on what operators can do directly to reduce emissions beyond what is required by regulation.

Given the diversity of the themes, a consistent method for comparing recommendations and assessing their trade-offs is required. To provide that, each of the recommendations were evaluated across two dimensions: the *impact* of the recommendations and their *feasibility*. These assessments incorporated both an assessment of their impact and feasibility for reducing GHG emissions, as well as for building societal and community engagement. The following were considered during the evaluation:

- Direct emissions impacts through the evaluation of addressable emissions, the maturity of the emissions reduction lever, and thus, the resultant estimated emissions impact
- Societal impacts as evaluated through the economic and community implications from each of the recommendations evaluated, considering avoiding or mitigating adverse impacts on communities, particularly the disadvantaged
- Enablement of emissions reductions, as well as building societal and community acceptance in the progress
- Feasibility of the recommendations, considering cost to implement, requirements for additional policy development, technology maturity, infrastructure requirements, and feasibility of support from societal and community stakeholders

As these recommendations were rated across the impact and feasibility dimensions, three groups of recommendations stood out and are summarized in Figure 5-15. Categorizing recommendations across these criteria helps to provide a perspective on future sequencing, specifically combining them according to relative groupings of impact and feasibility:

- **Foundation building**: Recommendations that demonstrate the highest potential impact and broadest reach over the long term. They are also critical for putting the U.S. natural gas sector on a lower-emissions pathway, like the Technology, Innovation, and Policy (TIP) Pathway. Specifically, many of these recommendations are critical for promoting the deployment of and investment in critical decarbonization technologies. However, these recommendations may take time to implement or face specific feasibility challenges. Therefore, efforts are required now to lay the groundwork for implementing these recommendations over the longer term.
- **Taking action**: Recommendations that are already in the process of being implemented or can be quickly initiated in the next one to two years. In many cases, these recommendations will help to enable GHG emissions reductions or may have limited impact individually as direct emissions reduction levers. Yet collectively, these recommendations can have significant impacts on GHG abatement, as they will help to shift the United States from the "Expected Pathway" toward lower-emissions pathways, like the "Continued Reductions Pathway."
- **Scaling impact**: Recommendations that build on those in the "Taking Action" category, enabling greater GHG emissions reductions over time. These recommendations may be more challenging to undertake. Thus, they are more likely to require several years to complete but will be critical for maximizing emissions reductions.

REPORT RECOMMENDATION THEMES AND CATEGORIES

	TAKING ACTION	SCALING IMPACT	FOUNDATION BUILDING
MEASUREMENT, MONITORING, REPORTING, AND VERIFICATION	Enhance capacity to monitor and report methane emissions Improve use of and confidence in GHG emissions reporting	Scale the use of emissions monitoring and reporting Harmonize GHG emissions data and tools	Deploy standards to differentiate GHG intensity of natural gas
SOCIETAL IMPACTS, BENEFITS, AND COMMUNITY ENGAGEMENT	Maximize effectiveness of community benefits; improve understanding of impacts	Build capacity for community engagement best practices; document impacts and benefits	Scale government incentives for and expand use of community benefit planning
INCENTIVES FOR GHG EMISSIONS ABATEMENT	Expand existing market mechanisms and voluntary initiatives	Introduce new market mechanisms, voluntary standards and tech. investment	Develop new economy-wide and/or sectoral market mechanisms
REGULATORY EFFECTIVENESS AND DURABLE POLICY	Maximize effectiveness and impact of existing and proposed regulations	Demonstrate, deploy, and harmonize technologies to support regulations	Implement durable policy to create a stable investment environment
INDUSTRY AND OPERATOR ACTIONS	Develop additional capabilities of oil and gas operators	Enhance industry and operator cooperation	Develop and deploy new methods for assessing industry progress

Figure 5-15. *Categorization of Recommendations*

The recommendations in this study suggest important actions that can contribute to the reduction of GHG emissions, especially for methane emissions. These include recommendations aimed at improving the effectiveness of methane regulations, promoting the development and deployment of detection technologies, and enabling greater emissions reporting and use of LCA methods and tools. Implementing these recommendations together can build a holistic platform for GHG emissions mitigation, focusing on several themes:

- *Building capacity to monitor and report methane* emissions through natural gas supply chains, especially through further development and deployment of measurement technologies
- *Improving the use of, and confidence in, GHG emissions reporting* through the harmonization of standards and greater availability of data
- *Maximizing the effectiveness and impact of existing and proposed regulations* by reducing the complexity of, and barriers to, implementation, and incorporating economic considerations into their design and implementation
- *Expanding existing market mechanisms and voluntary initiatives* to provide value to GHG emissions reductions efforts
- *Enhancing societal and community benefits* through improvements to existing government and community engagement approaches, including community engagement best practice sharing
- *Developing additional capabilities in oil and gas operators* by sharing best practices and enabling the adoption of common standards and tools for planning and implementing GHG emissions reduction efforts

As this platform for reducing GHG emissions from the natural gas sector is built and evolves, further recommendations contained in this

report will serve to scale impact. These recommendation themes include:

- *Scale the use of emissions monitoring and reporting* through the development of additional government and voluntary initiatives, especially to make actionable and useful data available
- *Demonstrate and deploy low GHG emissions technologies* to reduce CO_2 emissions across natural gas supply chains, especially electrification, low carbon intensity power, CCS, and LCI hydrogen
- *Harmonize GHG emissions data and tools* across industry, levels of government in the United States, and internationally
- *Build capacity for societal and community engagement* though community benefits plans and best practice sharing
- *Enhance industry cooperation* by developing new initiatives and tools to share investments, support national emissions reduction targets, and validate progress

Additional measures needed to make inroads in reducing remaining GHG emissions from U.S. natural gas supply chains were also described by recommendations in this report. Critical for this effort will be the development of incentives to promote capital deployment toward emissions reductions, especially to the large, and potentially growing, share of CO_2 emissions from natural gas supply chains. Five categories have been identified to provide a stable environment and generate the required incentives for investments in further reducing GHG emissions from gas supply chains:

- The implementation of *durable policy* will provide a stable and predictable environment to enable long-term investments, strengthen public trust and acceptance, and incentivize innovation in emissions reduction practices and the deployment of new technologies.
- The deployment of *market mechanisms* to value GHG emissions and incentivize investments in emissions abatement
- *Recognition that standards on lower GHG intensity or certified natural gas* can help to differentiate natural gas supply chains in which investments have been made to reduce GHG emissions intensity and enable the identification and value of less GHG-intensive sources of natural gas
- Support for *efforts to enhance the societal and community benefits* of investments in gas infrastructure, especially for investments in emissions mitigation measures
- Promotion of *international diplomatic efforts to recognize and incentivize investments* in reducing the GHG intensity of U.S. LNG, particularly recognizing the global benefits provided by the supply of U.S. LNG with potential to reduce GHG emissions in importing countries

The analysis of future GHG emissions pathways in Chapter 1 demonstrates how a lower-emissions future trajectory is possible (Figure 5-16). In total, GHG emissions from natural gas supply chains are projected to decline from around 444 MMT CO_2e in 2020 (GWP100) to between 360 MMT and 214 MMT in 2050, depending on the pathway. Most of this change is projected to be driven specifically by reductions in CH_4 emissions, accounting for around 150 MMT CO_2e of decline from 2020 to 2050.

The EPA projects more than 1.5 billion tons of CH_4 emissions reduction (as CO_2e) or an 80% reduction from 2024-2035 due to implementation of the New Source Performance Standards (NSPS) and the Waste Emissions Charge rules. While CH_4 emissions across natural gas supply chains are projected to decline over time, the share of CO_2 emissions is expected to rise. As more gas is used domestically and exported as LNG in the AEO2023 Reference Case the expected rise in CO_2 emissions is due to gathering and boosting, transmission, and liquefaction activities domestically to compress, transport, and liquefy gas that underpins the pathways. Based on EPA analysis of the U.S. GHG Inventory, the use of natural gas as fuel for compression, heat, and power, including drilling/completion activities, represented ~34% (~150 MMT CO_2e) of U.S. natural gas supply chain GHG emissions in 2020. Due to future reductions in methane and flaring emissions across the natural gas supply chain, emissions pathways in this NPC study suggest that supply chain natural gas combustion could represent 60%-80% of U.S. natural gas supply chain GHG emissions in

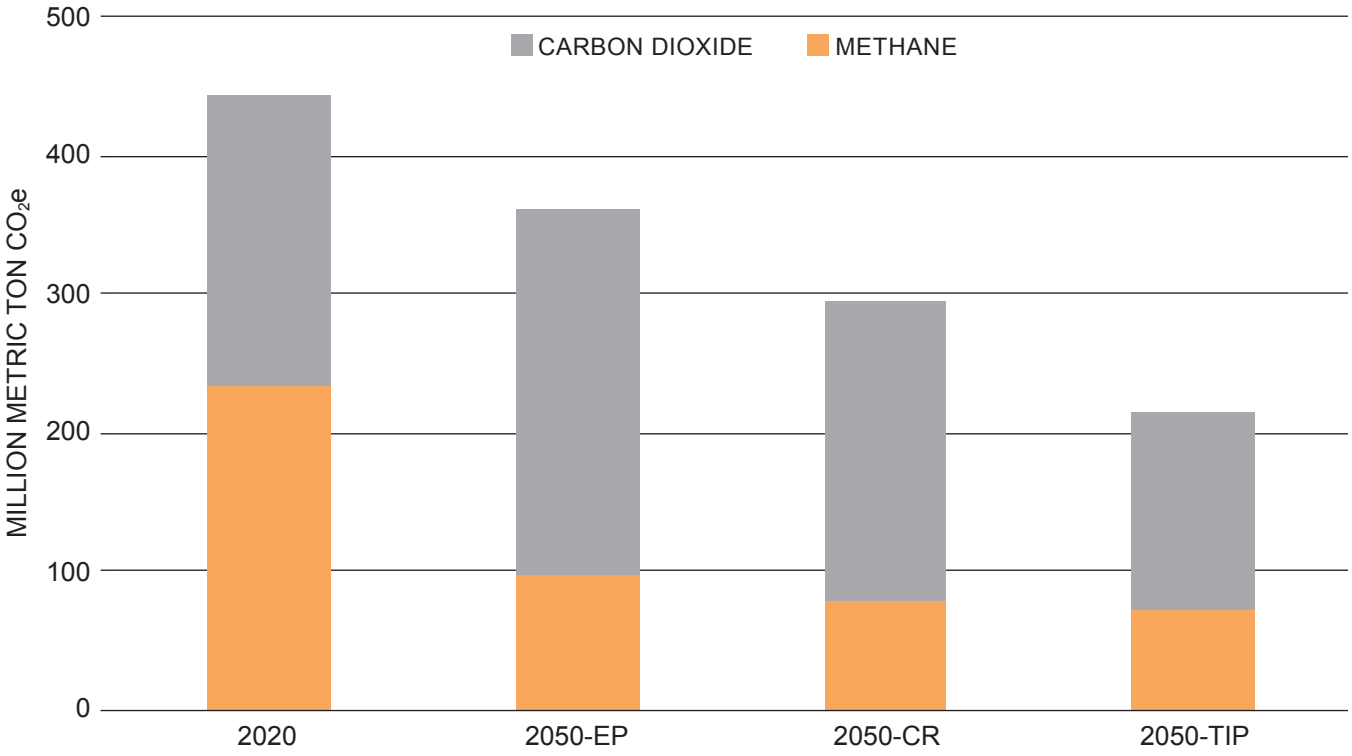


Figure 5-16. *Historic and Future Pathway GHG Emissions (GWP100)*

2050. A significant contributor to this increase is the combustion of natural gas to liquefy LNG. This reveals a constraint formed by the boundary of the Secretary's request: GHG emissions inside the United States increase, but the use of exported LNG in other countries, to the extent it displaces coal, has the potential to reduce the net GHG emissions worldwide. A consequential LCA analysis considering net GHG impacts in key countries where U.S. LNG is delivered will provide more robust understanding of the likely impacts of U.S. LNG to reduce GHG emissions worldwide.

To partially ameliorate the CO_2 emissions, the TIP Pathway mitigates CO_2 emissions through CCS. Societal impacts could be negative if not managed properly through meaningful community engagement as described in Chapter 2. Adding the energy security aspects of U.S. exports, LNG provides an excellent example of trade-offs as discussed elsewhere in this report.

To make even deeper reductions in GHG emissions from gas supply chains, it will be critical to address the growing segment of CO_2 emissions resulting from natural gas supply chains. This will require the deployment of emissions mitigation technologies, including electrification with low GHG intensity power, energy efficiency, CCS, and LCI hydrogen consumption within natural gas supply chains. Many of these technologies are still relatively nascent and lack large-scale demonstration for this application, such as carbon capture and hydrogen. Others, like electrification and energy efficiency technologies, have been demonstrated at a commercial scale but remain subject to the trade-offs and concerns stated previously. While not ubiquitous, electrification technologies continue to broaden in application across natural gas supply chains. Nonetheless, further investment in research, development, and demonstration of these technologies can drive up the technology readiness level and move them into deployment, while also reducing their costs.

FINDING 16: **CO_2 emissions from natural gas supply chains will grow, unless there is greater deployment of emissions abatement**

technologies, including electrification, carbon capture and storage, and low carbon intensity hydrogen.

RECOMMENDATION 15: *The NPC recommends that the federal government coordinate policies and initiatives for low carbon technology demonstration and deployment and to maximize GHG emissions reduction impacts within U.S. natural gas supply chains. Like current DOE programs supporting research, development, demonstration, and deployment activities for methane measurement and control technologies, there is an opportunity for DOE to develop a new program to support lower carbon intensity technologies to provide these needed functions in the U.S. natural gas industry. For carbon dioxide abatement, this includes but is not limited to deployment of carbon capture and storage in LNG liquefaction, scaling electrified solutions across gas supply chains, and enabling the availability of low-carbon power for relevant gas supply chain steps.*

A. Durable Policy

Energy systems have gone through significant changes over time. In the 1850s, wood produced 90% of energy in the United States. By 1910, coal was the dominant fuel, also accounting for 90% of energy. In the 1950s, oil and gas provided about 67% of energy needs.[19]

These transitions were brought about by the evolution of available resources or hardware. Energy is too deeply embedded in all aspects of the U.S. economic and social infrastructure to transition easily or quickly from one fuel to another. The operational changes necessary for large-scale energy transitions such as these must be accompanied by technological, behavioral, and values-driven shifts.[20] Major changes have occurred when new fuel types and technology came together to create new economic value.[21] The pairing of coal with the steam engine made industrialization possible; oil and the internal combustion engine enabled a mobile society; and various fuels and electricity created light, communication, and indoor temperature control.[22]

Despite this history of significant energy systems change, the United States has not previously undertaken an intentional policy effort to drive a transition to new fuels or technologies.[23] As described in the three goals enumerated in the Secretary's letter, current U.S. policy is to circumscribe energy choices to reduce GHG emissions. and, most recently, disproportionate impacts on disadvantaged communities. The energy system changes in the past created economic value that was captured in markets, from buying tickets for ocean travel, to paying utility bills for electricity, or buying a car to commute. In today's drive for energy transition, however, some results demanded from the transition are nonmarket public goods like energy security, affordability, low emissions, and a just transition.[24] Thus, without markets to support these characteristics of the modern energy transition, public policy must be developed to encourage change.

The design of energy policy is a critical driver of its effectiveness. An element of policy consideration that is often overlooked, but which is crucial to policy design, is durability.[25] A durable policy is one that withstands the test of time, remaining relevant, effective, and adaptable in the face of changing circumstances and needs.

19 Smil, V. *Energy Transitions: Global and National Perspectives, 2nd Edition.* Praeger. 2016. http://publisher.abc-clio.com/9781440853258.

20 Carlson, Ann E., and Robert W. Fri. "Designing a Durable Energy Policy." *Daedalus* 142 (1): 119–28. 2013. https://doi.org/10.1162/daed_a_00189.

21 Smil, V. *Energy in World History.* Routledge. 2019.

22 Schurr, S.H, et al. 1991. *Electricity in the American Economy: Agent of Technological Progress.* Greenwood Press. 2019.

23 Fri, R., et al. "The Alternative Energy Future: The Scope of the Transition." *Journal of the American Academy of Arts & Sciences Winter* 2. 2013https://www.amacad.org/sites/default/files/daedalus/downloads/Wi2013_Alternative-Energy-Future-Vol-2_0.pdf.

24 Fri, R., et al. "The Alternative Energy Future: The Scope of the Transition." *Journal of the American Academy of Arts & Sciences Winter* 2: 120. 2013. https://www.amacad.org/sites/default/files/daedalus/downloads/Wi2013_Alternative-Energy-Future-Vol-2_0.pdf.

25 Carlson, Ann E., and Robert W. Fri. "Designing a Durable Energy Policy." *Daedalus* 142 (1): 119–28. 2013. https://doi.org/10.1162/daed_a_00189.

Durable policy may include a set of guidelines, regulations, or principles developed and implemented by governments, institutions, or organizations that exhibit resilience and effectiveness over time. These policies are designed to endure beyond changing political climates, economic fluctuations, and societal shifts. Durable policies are marked by their adaptability and capacity to address evolving challenges without the need for constant reformation.[26]

Characteristics of durable policy include:[27, 28]

- **Relevance and flexibility**: Durable policies address fundamental issues or needs, allowing them to remain relevant over extended periods of time. They are not rigid; instead, they are designed to evolve and adapt to changing circumstances. They include mechanisms for periodic review and adjustment to ensure ongoing suitability.
- **Economic considerations**: To ensure policies can remain durable, considerations should be made for economic impacts and trade-offs. Policies that anticipate the relevant costs and benefits from their implementation are more likely to gain lasting support.
- **Stakeholder engagement**: Durable policies engage stakeholders from diverse backgrounds, interests, and expertise. By involving those who will be affected by the policy, policymakers can better anticipate and address their concerns, increasing the chances of long-term success.
- **Evidence-based**: Durable policies are rooted in evidence and thorough analysis. Decision-makers consider the available data, research, and expert opinions to develop policies that are effective when the policy is created and over time, incorporating new facts as they are discovered and validated. As knowledge, technologies, and learning evolve, durable policies must also evolve in a continuous cycle of adaptive management.
- **Political consensus**: Achieving political consensus is crucial for the durability of a policy. When policies have bipartisan or multipartisan support, they are less likely to face constant reversals or changes with each change in leadership, promoting long-term stability.
- **Transparency and accountability**: Durable policies are characterized by transparency in their formulation and implementation. They include mechanisms for accountability, allowing for scrutiny and assessment of their impact on society. Transparent processes build public trust and enhance policy durability.
- **Balanced objectives**: Durable policy aims to balance short-term goals with long-term vision. While addressing immediate concerns, durable policies also consider the potential consequences and benefits in the future, making them sustainable in the face of evolving challenges.
- **Continual evaluation:** A durable policy is subject to regular evaluation and assessment. It incorporates mechanisms for feedback, allowing for ongoing improvements and adjustments to meet changing needs and challenges.

The benefits of durable policy include:[29]

1. **Stability and predictability:** Durable policies provide stability in governance and the business environment, which is essential for economic growth and social well-being. Predictability allows individuals and businesses to plan with confidence.
2. **Economic growth:** Businesses and investors require stable and predictable policies to make long-term investments. Durable policies attract investments, promote economic growth, and create job opportunities.
3. **Public trust:** Policies that stand the test of time foster public trust in the government or organization responsible for their implementation. This trust is crucial for maintaining social cohesion and support for public initiatives.

26 National Research Council. *Limiting the Magnitude of Future Climate Change*. National Academies Press. 2010.

27 Jordan, Andrew J., and Brendan Moore. "Designing Durable Policies." *Cambridge University Press EBooks*, September 2020. pp. 29–54. https://doi.org/10.1017/9781108779869.004.

28 TCC Group for the Walton Family Foundation. "Pathways to Policy Durability: Insights for Advocates and Their Funders." 2022. https://www.tccgrp.com/resource/pathways-to-policy-durability-insights-for-advocates-and-their-funders/.

29 Carlson and Fri, *Daedalus*. 2023. pp. 122-123.

4. **Effective governance:** Governments that prioritize durable policies can focus on implementing and enforcing those policies, rather than engaging in frequent policy reversals or rewrites. This improves the efficiency and effectiveness of governance.
5. **Sustainability:** Many durable policies address environmental, social, and economic sustainability. By maintaining a long-term perspective, these policies help ensure the well-being of current and future generations.

FINDING 17: The implementation of durable policy will provide for a stable and predictable environment to enable long-term investments, strengthen public trust and acceptance, and to incentivize further innovation in emissions reduction practices and the deployment of new technologies.

RECOMMENDATION 16: *The NPC recommends that:*

- The oil and gas industry, along with federal and state governments, engage to design policies, including those recommended in this study, in a durable way.
- The oil and gas industry support and enable the development and implementation of policies that achieve these objectives.

B. Market Mechanisms

The primary characteristics of market mechanisms are that they provide a financial input to decision-making, either as an incentive by lowering costs, or as a benefit by creating value. The majority of natural gas supply chain elements are operated by for-profit entities (publicly traded, privately owned, and Tribal corporations and funds), and their primary metrics are, in broad generalization, safety and financial in nature. During the study, two paradigms for the delivery of GHG emissions reductions were identified: command-and-control regulations, and market-based mechanisms. Command-and-control regulations specify or prohibit certain activities and equipment, constraining the ability to reduce cost by the specificity of the regulation. Conversely, market-based mechanisms seek to encourage flexibility in emissions reduction methods, by providing various incentives for operators (individually and collectively) to reduce GHG emissions at the lowest cost, often to a degree that goes beyond reductions required by command-and-control regulations.

Implementation of market mechanisms should consider the balance between investments in reducing the GHG intensity of natural gas supply and the associated costs for reporting and accounting.

The types of market mechanisms identified during the study, along with the advantages and disadvantages of each, are discussed. The study did not attempt to select one preferred mechanism nor to force rank them. Historically, the regulatory process has created sector-specific GHG reductions rather than economy-wide market mechanisms.

An overview of the natural gas market illustrates how and where market mechanisms can be effective in reducing GHG emissions. In its simplest form, economics of the natural gas industry consists of the following:

- Deployment of capital to acquire and develop resources and the assets needed to produce and deliver those resources
- Earning revenue and return on investment from the sale of natural gas
- Operating expenses to pay for operations and maintenance associated with regulatory compliance costs and the safe and reliable production, transportation, and distribution of gas to consumers
- Business expenses, including taxes, fees, debt service costs, regulatory compliance costs, and returns paid to investors as dividends or distributions

The performance metrics used by the industry include Return on Capital and Free Cash Flow. Companies are incentivized to maximize both numbers, and, importantly, to maximize relative to other companies in the sector. Two formulas,

as simplified, show how these metrics are calculated:

Return on Capital = (Revenue – Operating Expense – Business Expense)/Capital Deployed

Free Cash Flow = Revenue – Operating Expense – Business Expense + Depreciation

The market mechanisms discussed in this chapter will be used to evaluate ways to help companies decrease the operating and business expenses needed to reduce emissions, to decrease the cost of capital deployed to achieve emissions reduction, and in some cases, to potentially increase revenue.

1. Investment Decision-Making by the Natural Gas Industry

The petroleum industry, within which the natural gas industry is a major part, has a widely established and structured process for decision-making, primarily driven by the longtime cycles of natural gas development projects. It is not uncommon for a company to invest for three to six years before starting operations, and then to operate that asset for 20 or more years. A company must evaluate both the capital cost for a project invested before starting up production, and the long-term operating, business, and maintenance costs over the life of the project. While the shale revolution initiated in the early 2000s in the United States added shorter-life assets to the upstream sector, those resources still involved decadal-scale decisions on upstream, midstream, and transportation assets. Each of these decisions involved uncertainties, however even with these uncertainties, certain key questions that a company in the natural gas supply chain will ask before investing in an emissions reduction action are known, including:

- How much will this reduce the carbon intensity of my operation, as documented through a voluntary or mandatory reporting framework?
- How much capital will be required to achieve this reduction?
- What will be the impact of this action on my operating and business costs and revenue?
- Will my operations be competitive after making this investment?

Market-based mechanisms are ways to help operating companies make decisions based on changes to capital and costs. While a discussion of natural gas pricing is out of scope for this study, the potential for low carbon intensity natural gas to attract a green premium, and potential mechanisms to enable that possibility, will also be addressed.

Across the supply chain, verification of emissions reduction results is an important contributor to both actual reductions and public trust in operators' reported reductions. This could be achieved by employing third-party verifiers or internal teams following ISO 14064-3 standards, regulatory standards such as AB 32, and potentially other third-party verification protocols such as GIIGNL, Veritas, MIQ, and Project Canary if consistent with ISO or regulatory standards.

2. Categories of Market Mechanisms

A literature search on research and analysis regarding the categorization of market mechanisms showed that the following categories cover most, if not all, mechanisms:

- GHG emissions intensity standards
- Carbon pricing mechanisms
- Valuation of emissions reductions
- Supply incentives
- Demand incentives

Prior NPC studies have advocated for an economy-wide price on carbon. In this study, rather than reiterating that recommendation, the NPC has chosen to describe a broader suite of market mechanisms, along with the advantages and disadvantages of each.

a. Performance Standards That Generate Certificates

Some performance standards have attributes that are based on emissions intensity or absolute emissions and can generate certificates or attributes that can be tradeable or retired.

Performance standards set a goal to be achieved by each operator and allow the operator to select their preferred method of achieving the standard.

An example of a performance standard is the North Dakota Industrial Commission (NDIC) policy on reducing flared gas.[30] Between 2014 and 2020, NDIC set gas capture goals for each operator starting at 74% and up to 91%. Operators were allowed to accumulate credits on a rolling six-month basis, could apply the credits in case of one of six defined extenuating circumstances, and were forbidden to transfer credits to another operator. Unused credits expired after six months. Operators were incentivized to exceed gas capture targets by banking and using excess credits in case of a process upset in the future. As of April 2023, statewide gas capture in North Dakota was 95%. Colorado's Greenhouse Gas Reporting and Emissions Reduction Requirements (Regulation Number 22) are another example of a performance standard.[31] The EPA methane Waste Emissions Charge may also be considered a performance standard, albeit one that does not generate tradeable certificates.

b. Sectoral-Specific Market Mechanisms

Renewable or clean energy standards tend to be proscriptive and sector specific. These exist in the electricity generating, transportation fuels, and other sectors in the United States. These specify targets that drive developments of new technology. Examples include:

- **Renewable Portfolio Standards (RPS)** for power generation—adopted by 29 states and the District of Columbia (D.C.)—require a certain percentage of a utility's electricity to come from renewable energy sources, of which 12 states and D.C. have a requirement for 100% clean electricity by 2050 or earlier.
- **Clean Energy Standards (CES)**—adopted by seven states—require a certain percentage of a utility's electricity to come from low- or zero-carbon emitting energy sources.[32]

The standards range from modest to ambitious, and qualifying electricity sources vary. Some states also include carve-outs (requirements that a certain percentage of the portfolio be generated from a specific energy source, such as solar power) or other incentives to encourage the development or maintenance of resources (e.g., nuclear power) in their standards.

California has a Low Carbon Fuel Standard (LCFS) program that is intended to reduce carbon emissions in transportation fuel. The LCFS standards are expressed in terms of the CI of transportation fuels (e.g., gasoline, diesel). Within the program, producers and importers of conventional fuels must reduce the average CI of their fuels with respect to a specific target every year. This can be done by producing or acquiring low-carbon fuels and blending these with conventional fuels, implementing GHG reduction projects for producing crude oil or petroleum products (e.g., CCS), and/or by acquiring credits from other entities that have excess credits. Low-carbon fuels with CI below the standard for a particular year generate credits, while fuels with CI above the standard generate deficits.

In the context of market access, regulators define what energy source is considered low carbon and, by exclusion, which energy sources are not. By incorporating the reduced CI of natural gas in the definition of low-carbon fuel standards, regulators could incentivize natural gas producers and marketers to offer gas into their markets that meets or exceeds the defined CI.

c. Carbon Pricing

There are two main types of carbon pricing:[33] emissions trading systems and carbon taxes.

- An emissions trading system (ETS), sometimes referred to as a cap-and-trade system, caps the total level of GHG emissions and allows those industries with low emissions to sell their extra allowances to larger emitters. By creating supply and demand for emissions allowances, an ETS establishes a market price for GHG emissions. The cap helps ensure that the required

30 North Dakota Industrial Commission. "Presentation of the Department of Mineral Resources Review of North Dakota Petroleum Council Flaring Task Force Report and Consideration of Implementation Steps." March 3, 2014. https://www.dmr.nd.gov/oilgas/presentations/NDIC030314_100.pdf.

31 Colorado Greenhouse Gas Reporting and Emission Reduction Requirements. 5 CCR 1001-26. Code of Colorado Regulations, Secretary of State, Colorado. July 1, 2019. https://www.dmr.nd.gov/oilgas/presentations/NDIC030314_100.pdf.

32 EIA. "Renewable Energy Explained: Portfolio Standards." 2016. https://www.eia.gov/energyexplained/renewable-sources/portfolio-standards.php.

33 World Bank. "Pricing Carbon." 2016. https://www.worldbank.org/en/programs/pricing-carbon#:~:text=There%20are%20two%20main%20types.

emissions reductions will take place to keep the emitters (in aggregate) within their preallocated carbon budget.

- A carbon tax directly sets a price on carbon by defining a tax rate on GHG emissions or, more commonly, on the carbon content of fossil fuels. It is different from an ETS in that the emissions reduction outcome of a carbon tax is not predefined, but the carbon price is.

i. ETS, also known as cap and trade, with government-issued emissions allowances

A cap-and-trade system sets an overall limit on emissions or emissions intensity, requires entities subject to the system to retire sufficient allowances to cover their emissions, and provides broad flexibility in the means of compliance. Entities can comply by undertaking emissions reduction projects at their facilities and/or by acquiring allowances (or credits) from the government free of charge, or by purchasing additional emissions allowances (or credits) from the government or from other entities that have reduced emissions below the number of allowances held. A carbon leakage protection mechanism, also called a carbon border adjustment mechanism, can (so long as it is well designed) also be added to an ETS or carbon tax, to protect against the unintended consequence that activity of energy-intensive trade-exposed sectors within the boundary of the ETS or carbon tax could be lowered by transferring the activity outside of the covered area to decrease emissions.

Examples of cap and trade include the EPA program for reduction in ozone-depleting gases and sulfur dioxide, both authorized by the 1990 Clean Air Act amendments,[34] the Regional Greenhouse Gas Initiative to cap CO_2 emissions from power plants in New England and Mid-Atlantic states,[35] and the California GHG program,[36] which initially covered electric generators and industrial plants and has been expanded to include transportation fuel distributors. The EU Emissions Trading System,[37] another cap-and-trade system, requires participation by GHG emitters in around 10,000 installations in the energy and manufacturing sectors, and intra-EU aircraft operations. Today, this covers around 40% of EU's emissions; the maritime transport sector is planned to start in 2024 and be fully phased in by 2026. In that system, a cap is a limit set on the total amount of emissions allowances released to the ETS market. ETS installations must surrender those allowances annually to cover their verified emissions. The cap is reduced annually in line with the EU's climate target, ensuring that emissions decrease over time. Companies primarily buy allowances on the EU carbon market, but they also receive some allowances for free. Companies can also trade allowances with each other as needed. If an installation or operator reduces their emissions intensity, they can either keep the spare allowances to use in the future or sell them.

ii. Carbon tax

A carbon price is a tax or fee that is assessed on post-combustion GHG emissions or on the carbon content of fossil fuels, precombustion.

A carbon tax can be assessed at the point of emissions (i.e., at the point where GHG enters the atmosphere). Alternatively, a carbon tax can be assessed on the embedded carbon emissions in a product, emissions resulting from manufacturing processes (e.g., cement production). An attributional LCA is an appropriate mechanism for calculating the embedded carbon emissions in a product.

Carbon taxes have been subject to significant analysis,[38] primarily on the incidence (who pays the tax) and distributional effects (how the revenue is used), and on the macroeconomic impacts. These effects are not unique to a carbon tax, as they also occur with cap-and-trade and regulatory frameworks. A carbon tax also risks leakage through the transfer of carbon-emitting activities

34 See, for example, Highlights of the Clean Air Act 1990 Amendments: https://www.epa.gov/sites/default/files/2015-11/documents/the_clean_air_act_-_highlights_of_the_1990_amendments.pdf.

35 Regional Greenhouse Gas Initiative, an Initiative of States of the Eastern US. n.d. https://www.rggi.org/.

36 California Air Resources Board. "Mandatory Greenhouse Gas Emissions Reporting." n.d. https://ww2.arb.ca.gov/our-work/programs/mandatory-greenhouse-gas-emissions-reporting.

37 European Commission. "EU Emissions Trading System." n.d. https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets_en.

38 Metcalf, Gilbert E. *Paying for Pollution: Why America Needs a Carbon Tax*. Oxford University Press. 2019.

outside the jurisdiction of the carbon tax, potentially resulting in no reduction of, or an increase in, worldwide GHG emissions. This leakage of emissions-producing business activities outside the covered area generates demand for border adjustments at the boundary of the covered area to attempt to correct for the transfer of activities (most frequently, energy-intensive trade-exposed goods) out of the covered area. While a full analysis of these effects is beyond the scope of this study, they are discussed in brief.

Examples of a carbon tax are the Btu tax proposed by the Clinton administration in 1993,[39] which taxed all energy consumption, with fossil fuels at a higher rate than other sources of energy, and the proposed Baker-Schulz Carbon Dividends Plan,[40] which would assess a fee on all post-combustion CO_2 emissions across all sectors. A study on the technical basis for border adjustments has been proposed in U.S. legislation S.1863 the Providing Reliable, Objective, Verifiable Emissions Intensity and Transparency Act of 2024 (or the PROVE IT Act),[41] which required a study to evaluate the average CI of several U.S.-manufactured products and similar products manufactured in foreign nations.

The United States instituted its first tax on GHGs through the U.S. IRA Methane Waste Emissions Charge (Methane Emissions Reduction Program or MERP),[42] herein referred to as a methane fee. The methane fee will be assessed on the oil and natural gas sector for each segment of the supply chain based on predetermined methane emissions threshold. The key issue remains the technological challenge to quantify methane emissions accurately. As discussed in this study, a pricing system requires precise and accurate carbon accounting to be fair and cost effective.

MERP, authorized in the IRA, places a fee on methane emissions from the oil and gas sector. This fee would be an operating and business expense for the operator, starting at $900 per ton of methane emitted (above a specified threshold for each segment of the supply chain) and rising to $1,500 per ton.[43] One of the most significant incentives would be the ability of operators to use their own actual/measured emissions for submittal to EPA, in lieu of EPA's emissions factors. This subject—measurement-informed reporting—was described in Chapters 1 and 3.

Drivers or incentives for emissions reduction are already included in the study's Existing Policies Pathway. First, upcoming EPA regulations will be a driver in creating a floor for emissions reductions for new and modified sources in the near future (in accordance with NSPS OOOOb requirements)[44] and for older sources in the next four to five years (in accordance with regulations pursuant to NSPS OOOOc guidelines).[45]

The Congressional Budget Office evaluated the methane fee[46] and noted: "Charging for methane emissions creates an economic incentive for companies to reduce emissions. Because a company pays for each unit of methane it emits, it will reduce emissions up to the point at which the cost of doing so exceeds the charge and only pay the charge for its remaining emissions. The expense

39 Baron, R. "Economic/Fiscal Instruments: Taxation (i.e., Carbon/Energy). Annex I Expert Group on the United Nations Framework Convention on Climate Change, Working Paper No. 4, Organisation for Economic Co-operation and Development." OECD. 1997. Retrieved 2010-04-22.

40 CLC Council. Baker-Schulz Carbon Dividends Plan. "Bipartisan Climate Roadmap." August 2021. https://clcouncil.org/reports/Bipartisan-Climate-Roadmap.pdf.

41 U.S. Congress, Senate, *Providing Reliable, Objective, Verifiable Emissions Intensity and Transparency Act of 2024 or the PROVE IT Act of 2024*, S. 1863, 118th Congress. Reported to Senate January 25, 2024. https://www.congress.gov/bill/118th-congress/senate-bill/1863.

42 EPA. "Methane Emissions Reduction Program." n.d. https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program.

43 Office of Management and Budget. "86 FR 24669: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990" *Federal Register*, 86 (87). May 7, 2021; 24669.

44 EPA. "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." *Federal Register* 87, no. 233. December 6, 2022. 74702. https://www.govinfo.gov/content/pkg/FR-2022-12-06/pdf/2022-24675.pdf.

45 EPA. "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." *Federal Register* 89, no. 47. March 8, 2024. 16820. https://www.govinfo.gov/content/pkg/FR-2024-03-08/pdf/2024-00366.pdf.

46 Congressional Budget Office. "How CBO Analyzes the Effects of Charging the Oil and Gas Industry for Methane Emissions." 2022. https://www.cbo.gov/publication/58444#:~:text=A%20charge%20for%20methane%20emissions%20decreases%20the%20a.

of producing natural gas will increase by the combined cost of the reduction in emissions and the amount charged on remaining emissions. Because methane emissions are often associated with a loss of marketable natural gas, some of that expense will be offset by the value of capturing the gas that would otherwise have been lost. That value is unlikely to fully offset the cost of reducing emissions: If an action to reduce emissions was profitable, the company would already be taking that action."

The IRA MERP[47] is one example of a narrowly tailored carbon tax—one that is both sector specific (oil and gas) and product specific (methane). The most inclusive carbon tax is one that is economy-wide, one that taxes all sectors and all GHG emissions. There are any number of ways to select sectors and products upon which a carbon tax is applied, and a detailed analysis of each of these is beyond the scope of the study. However, a nuanced evaluation of carbon tax inclusions, exemptions, and commodity-specific aspects is provided elsewhere.[48]

For the purposes of this study, an economy-wide carbon tax would, as constrained by the study scope, only apply to the GHG emissions through the natural gas supply chain. The study recognizes that an economy-wide carbon tax would also put downward pressure on natural gas demand, but an evaluation of that effect is beyond the scope of this study.

Alternatively, an operator can incorporate their own assumed and implied carbon price and apply that to investment decisions. As this is created by the operator themselves based on the operator's view of a potential future carbon tax, this would differentially incentivize investments by that operator in emissions reduction.

d. Investment Incentives at the Asset and Business-Unit Level

i. Incentives applied to capital

Capital investments can be sourced from equity (the owner's portion of the company's assets) or debt. As operators evaluate ways to reduce emissions, capital investment costs are one element included in their decision. Emissions reductions compete for capital along with all other types of investment, from new wells to major maintenance, new pipelines and compressors, and other equipment and facilities. The cost of capital for a company in the natural gas supply chain is, broadly speaking, the same for investments that reduce emissions as for investments in anything else; and a significant factor on the cost of capital is the tax treatment of the investment. While a lengthy evaluation of tax policy and regulation is beyond the scope of this study, well-proven tax mechanisms to incentivize the desired investment include:

- Depreciation schedules that accelerate the depreciation of certain asset types
- Current-year expensing in lieu of multiyear depreciation
- Investment tax credits and grants

ii. Lower cost capital

Lower cost capital, targeted for investment in emissions reduction equipment, can be made available to companies. Sustainability-performance-linked loans, in which funds from the loan must be applied toward financing a specified emissions reduction project, are further described later in this chapter. Tax credits that are directly indexed to CI would be a targeted way to incentivize investments in emissions reduction for natural gas differentially; an example of this is the 45V tax credit for LCI hydrogen[49] with a tax credit value that increases as the CI of the hydrogen decreases.

iii. Congressional incentives

These are grants, made available through the U.S. IRA MERP (Sec. 60113) and Sec. 50161,[50] allocated to EPA, and administered by DOE under

47 EPA. "Methane Emissions Reduction Program." n.d. https://www.epa.gov/inflation-reduction-act/methane-emissions-reduction-program.

48 Metcalf, Gilbert E. *Paying for Pollution: Why America Needs a Carbon Tax*. Oxford University Press. 2019. https://academic.oup.com/book/25554.

49 DOE. "Clean Hydrogen Production Tax Credit (45V) Resources." December 19, 2023. https://www.energy.gov/articles/clean-hydrogen-production-tax-credit-45v-resources.

50 U.S. Congress, House. *Inflation Reduction Act of 2022*, H.R.5376, 117th Congress. Introduced September 27, 2021. Became Public Law No. 117-169 August 16, 2022. https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

its existing grant-making process. These grants incentivize deployment of methane detection systems and the plugging and abandonment of marginal conventional wells.

e. Voluntary Corporate Mechanisms

The following mechanisms, while not strictly speaking market mechanisms, would align with emissions reduction goals and assist in a company's investment decisions by enhancing the valuation of emissions reduction measures. They also reduce uncertainty in investment decisions by providing indirect incentives.

i. Corporate social responsibility considerations

In response to demands from shareholders, stakeholders, and civil society, a company may make a commitment to GHG emissions reduction. This may range from aspirational, Paris-aligned strategies to measurable reduction in specified GHG emissions in specific geographic areas.

There are several voluntary methane emissions reduction approaches and enhanced reporting programs that operators can use to better estimate emissions based on empirical data and measurements. While there may not be immediate financial benefits associated with these approaches, the resulting goodwill may encourage operators to participate in these initiatives. One such initiative is the U.N. Environment Programme's OGMP 2.0 program.[51] This program requires the development of a measurement-based emissions inventory for methane. Participants are awarded the Gold Standard based on their implementation plan and/or reported emissions. The OGMP 2.0 program could help distinguish such operators. Additionally, the DOE is developing a measurement, monitoring, reporting and verification (MMRV) protocol that could be another standardized approach for operators to base their emissions reporting.[52]

It should be noted that proposed revisions to the EPA's Greenhouse Gas Reporting Program (GHGRP) Subpart W[53] may be more comprehensive, when finalized for the United States and harmonized with other regulations, than OGMP 2.0.

ii. Availability of capital markets (equity and debt)

While the cost of capital and its incentives have already been discussed at the asset level, another incentive is the actual availability, or lack thereof, of debt and equity.

Financial services providers can preferentially decide to finance projects that reduce GHG and/or companies that are reducing CI. These providers can differentially incentivize emissions reduction investments through the preferential allocation of capital.

One metric used by some financial institutions to evaluate their financed emissions is produced using the following calculation:

$$\textit{Absolute Financed Emissions} = \Sigma\,[(\textit{Exposure}/\textit{EVIC}) \times \textit{Emissions}]$$

Where:

- Exposure is the financial value at risk between the financer and the client
- EVIC is the client's Enterprise Value Including Cash
- Emissions are the absolute emissions reported by the client

iii. Insurability of natural gas activities

Certain insurance carriers in primary and secondary (reinsurance) markets are limiting the amount of oil and gas business they underwrite in response to growing pressures to address climate change and to encourage the transition to a net zero economy. However, insurance products tied directly to a company's CI have not yet appeared on the market, and the primary and secondary (reinsurance) markets have shown limited reduction in capacity to insure natural gas activities.

51 U.N. Environment Programme. "The Oil & Gas Methane Partnership 2.0." n.d. https://www.unep.org/topics/energy/methane/international-methane-emissions-observatory/imeo-action/methane-alert-and.

52 DOE Office of Fossil Energy and Carbon Management. "Greenhouse Gas Supply Chain MMRV Framework." March 14, 2024. https://www.energy.gov/sites/default/files/2024-03/MMRV%20Framework%20US%20Stakeholder%20Meeting_Final_14_March_2024.pdf.

53 EPA. "Greenhouse Gas Reporting Program, Subpart W – Petroleum and Natural Gas Systems." Updated May 6, 2024. https://www.epa.gov/ghgreporting/subpart-w-petroleum-and-natural-gas-systems.

Information is limited, and published examples consist mostly of headline announcements of companies withdrawing from specific segments (coal, oil sands, arctic), hence it is challenging to draw any conclusions regarding the potential for insurability to act as a market mechanism for emissions reduction.

f. Commodity Markets Access Incentives

i. Green premiums in regulated natural gas purchases for certified gas

Natural gas operators and energy regulators have evaluated three options for certified gas to serve as a market mechanism to reduce GHG emissions across the natural gas sector, each with different advantages and challenges. These three options include the following:

- Regulators could approve cost recovery for any incremental price paid by the service provider to the seller of certified gas; this may require legislation at the state level to give the state regulator statutory authority to approve the pass-through of certified gas costs to consumers.
- Utilities can finance the incremental cost of certified gas by absorbing any incremental costs for certified gas purchases as an increase in operating expenses and a decrease in profits.
- Utilities may offer certified gas to customers on a voluntary basis. Customers could choose to enroll and pay a premium for some or all of their natural gas consumption. These transactions generally require the regulator to approve rates and terms, without making it an approved form of cost recovery.

While the lack of a consistent standard for the MMRV of methane and carbon dioxide emissions continues to limit development of the differentiated gas market, progress is being made. The NAESB (which participated in this study's Coordinating Subcommittee) has created a certified gas addendum for the Base Contract for Sale and Purchase of Natural Gas,[54] which provides a standardized transaction template with customizable flexibility for certified gas transactions. Use of this addendum allows, but does not require, gas sellers and buyers to incorporate a premium price. It does not define the methodology to provide reasonable assurance on the CI of the certified gas; that is left to mutual agreement of the buyer and seller. Assurance of CI requires addressing what combination of standards and certifying methodologies would provide reasonable assurance and is discussed elsewhere in this study. The DOE is leading an international working group of more than 15 countries, as well as domestic and international stakeholders, to develop an MMRV framework that could facilitate a more trusted and transparent assessment of methane and carbon dioxide performance in the global gas market.[55] That process is ongoing and not likely to conclude until mid-2025 but, once concluded, could help drive standardization in MMRV protocols across both international and domestic supply chains. DOE has clearly stated that its MMRV program is not "Responsibly Sourced Gas."

In addition to developing market demands driven by natural gas-fired electricity generation and end users seeking to meet their own decarbonization goals, the premium price concept could be operationalized by state Public Utilities Commissions (PUC). These commissions could support a certain level of cost recovery for certified gas purchases, consistent with state and utility climate goals, but only to the extent such certifications are based on trusted and transparent MMRV frameworks. The ability for regulated utilities to enter into agreements to purchase certified natural gas and pass the cost onto the end user would activate this market mechanism. This is an emerging area for further work by industry and regulators. An example of action that may lead to this is New York's Climate Leadership and Community Protection Act.[56] The act establishes GHG emissions reporting requirements and "requires that statewide GHG emissions include...greenhouse gases produced outside of the state that are associated

54 A press release about the North American Energy Standards Board's 2023 standardized addendums for renewable natural gas and certified gas can be found here: https://www.naesb.org/pdf4/031623press_release.pdf.

55 DOE Office of Fossil Energy and Carbon Management. "DOE Announces Global Collaboration to Reduce Methane Emissions." November 15, 2023. https://www.energy.gov/fecm/articles/doe-announces-global-collaboration-reduce-methane-emissions.

56 New York State Senate. "New York State Climate Leadership and Community Protection Act." 2019. https://www.nysenate.gov/legislation/bills/2019/S6599.2.

with...the extraction and transmission of fossil fuels imported into the state."[57]

As with any natural gas purchases by a customer in the United States, a physical molecule of a gas produced by an operator does not always make its way to the end-customer. Rather, the transportation of gas relies on system balances. Similarly, as discussed elsewhere in the study on supply chains and emissions allocation through the SLiNG-GHG LCA model, it is unlikely a specific natural gas molecule would move from wellhead to consumer along the same physical pathway as the segments used to calculate the CI of that gas as delivered. Industry, however, has developed commercial enabling mechanisms for custody transfer, pipeline and gas plant tariffs, and liquefaction, which allow, with sufficient MMRV, documentation of the CI as delivered to the customer.

ii. LNG export markets

Certain LNG markets, notably EU countries and Japan, are considering various programs that incorporate methane and/or GHG emissions intensities. These are covered in Chapter 4.

3. Evaluating Market Mechanisms

The effectiveness of a regulatory mechanism is evaluated by (1) whether it achieved the legislated target(s)—that, typically, are a specified level of emissions—and (2) whether the target was achieved at the lowest cost to society or responsible parties. These apply to both command-and-control as well as market-based regulatory mechanisms. Three factors that are useful in scoring the effectiveness of market mechanisms, through the lens of advantages and disadvantages can be found in Section III.B.6 "Examples of Market Mechanisms." They are:

- **Incentive to innovate in reducing emissions**: Does the market mechanism incentivize operators to find innovative ways to deliver emissions reductions and/or reduce emissions more than is minimally required? Key aspects of innovation incentives include:
  - Allowing the company to select the most cost-effective technologies, including methods to qualify new technologies
  - The ability of one company with cost advantages to reduce emissions more than their proportional requirement, with the ability to trade those excess reductions to other operators that face cost barriers
  - Cost avoidance: Does emissions reduction allow the operator to avoid a cost (i.e., carbon tax or emissions allowance) and thus incentivize the most cost-effective reduction pathway?
  - Competitiveness: Does the policy framework enable an operator to remain competitive in global markets while investing in GHG emissions reduction?
- **Compliance cost certainty**: How are the costs of compliance determined and are they known by the operator at the time decisions for emissions reduction expenditures are made?
- **Emissions reduction certainty**: To what extent is the absolute quantity of emissions reduction known at the time the market mechanism is put in place?

4. Decision-Making Under Uncertainty

The natural gas industry has developed methods to account for uncertainty and to incorporate post-final investment uncertainty into decision-making. Historically, conventional natural gas development industry excelled at processing subsurface uncertainty, such as whether resources are present and can be produced efficiently. Both classic gas reservoir and newer shale gas development investment decisions strive to incorporate future uncertainties in regulatory and market conditions. The impact of these uncertainties can materially change the development options, for example, by adding contingencies and flexibility that are detrimental to value but that could be removed if the investment environment is perceived to be more certain.

One of the key uncertainties is regulatory durability—the expectation that regulations in place at the point of a final investment decision will remain in place during the expected life of the investment. There is an asymmetric element to

57 New York State Senate. "New York State Climate Leadership and Community Protection Act." 2019. https://www.nysenate.gov/legislation/bills/2019/S6599.2.

this uncertainty—if regulations incentivizing an investment are rolled back, then the investment might be disincentivized, and the company may regret having made the decision.

5. Application of Market Mechanisms

Methane-related market mechanisms are dependent on a robust measurement and quantification process, which has been discussed in Chapters 1 and 3 of this study; ideally an MMRV process applicable for compliance purposes would also be used for performance metrics in a market mechanism.

The market-based mechanisms, and the costs associated with implementing them, are stackable, meaning, for example, the MERP, low CI differentiated gas premium, and an operator's voluntary near-zero methane target are not mutually exclusive.

The next section describes several market mechanisms with some of the potential advantages and disadvantages of each individual market-based approach. Certain elements are common across different market-based approaches in a well-designed application, including the need for:

- Having accurate measurement, reporting, and verification of emissions under the program
- Considering the availability and cost of existing technologies that would be needed to meet the standard or policy design
- Considering the potential for trade-offs between emissions reductions and other energy system goals, like reliability of support and affordability of energy
- Understanding that modernization may require work on assets located in, and potentially impacting, disadvantaged communities

6. Examples of Market Mechanisms

In this section we describe the features of market mechanisms, along with some key advantages and disadvantages of each. A thorough evaluation of the advantages and disadvantages is beyond the scope of this study, as these are highly dependent on the detailed design of the mechanism.

a. Performance Standards: Set Emissions Limitations Standards

- **Feature:** Support investment in new equipment
  - **Advantages:** The standards fundamentally change the capital stock by incentivizing modernization of equipment before the actual expected useful life or the early retirement of high-emitting legacy equipment. Potential for resiliency improvements can be a cobenefit. The capability to meet or exceed the emissions limitation standards with fungible credit would accelerate retirement of assets and new investment. This feature can incentivize deployment of new technology.
  - **Disadvantages**: Directs allocation of capital disconnected from asset life. If a performance standard overemphasizes one category of emissions (e.g., GHG) over another (e.g., ozone precursor), it may not be the most cost-effective emissions mitigation pathway.
- **Feature**: Achieves targeted reduction in GHG impact-supply chain
  - **Advantages:** Technology-neutral standards allow the operator to select the most cost-effective way (including investment, operating practices, etc.) to achieve reduction.
  - **Disadvantages:** Requires contractual and liability aspects between segment operators (e.g., upstream, midstream), which historically have been at arm's length. This was identified as a primary concern among Less Capitalized Operators. Individual supply chain segment emissions may decrease, but total LCA emissions may not.
- **Feature:** Flexibility
  - **Advantages:** Flexibility means an operator chooses the best way to meet the standard set by the regulator. With tradeable components, operators are incentivized to exceed the standard if their way is more cost effective than other operators. This flexibility can be used to accelerate rollout and capture otherwise-overlooked opportunities.
- **Feature:** Performance metrics
  - **Advantages:** Standards are generally clear in their metrics

- **Disadvantages:** In cases of emissions elimination by new equipment, requires operator to prove the absence of emissions

- **Feature:** Shifting the location of GHG emissions
  - **Disadvantages:** Potential risk of carbon leakage impacts on trade-exposed industries that is more difficult to mitigate than with other market-based approaches

b. Renewable Portfolio (RPS) and Clean Energy Standards (CES)

- Obligate preferential dispatch and capacity contracts for selected amounts of renewable generation and procurement of specified fuel types, or
- Cap-and-trade quantity of CO_2e emissions set by regulator; market sets price for cost per unit of emissions (i.e., emissions are fixed, and cost varies)
- **Feature:** Achieves targeted reduction in GHG
  - **Advantages:** Standards have clear targets that provide tangible reduction expectations that should be tied directly to the cost-benefit analysis at the regulatory development stage. The regulator's approved emissions reduction goals and metrics are met.
  - **Disadvantages:** Requires significant planning and implementation effort due to the prescriptive nature of the policy approach. The CI is set by regulators using arbitrary LCA model boundaries that are often not inclusive of emissions across the entire supply chain. Electricity dispatch stack may require use of higher-emissions sources during peak load, increasing the average CI; incentivizing reductions in emissions during peak periods can be more challenging and requires separate policy structures within the RPS or CES.
- **Feature:** Technology advancement
  - **Advantages:** Regulators can incentivize the creation and deployment of new technology by setting standards.
  - **Disadvantages:** Regulators may set standards that are expensive or impossible with existing technology. Costly new technology may create demands for additional incentives (e.g., grants, loans, and subsidies) or approvals of pass-through costs to consumers. Technology forcing can have higher expectations of success than are achievable in the field.
- **Feature:** Shifting the location of GHG emissions
  - **Disadvantages**: Potential risk of carbon leakage impacts on trade-exposed industries that is more difficult to mitigate than with other policy approaches; boundary setting for an LCA can be a mitigation

c. Market Instrument: Cap and Trade

- Quantity of CO_2e emissions set by regulator; market sets price for cost per unit of emissions (i.e., emissions are fixed and cost varies).
- **Feature:** Balances price and emissions reduction by setting emissions goals
  - **Advantages**: A cap-and-trade administrator sets the cap for emissions and the market responds, setting the price of trade of emissions between regulated entities across the sector. Market-based pricing ensures all sector participants see the same clearing price per unit of CO_2e emissions.
  - **Disadvantages**: Focus may be shifted to revenue generation and fiscal policy rather than environmental policy, especially during times of lower economic output. Market pricing may require regulator intervention if prices rise too high (impacting consumer affordability) or too low (punishing companies that spent above that price to reduce emissions), which can be managed with well-designed cost-containment provisions.
- **Feature:** Investment incentive in GHG reductions
  - **Advantages**: Allowances or other emissions credit instruments under cap and trade can be used in arbitrage and traded in secondary markets, encouraging the lowest-cost emissions reductions projects in each sector.
  - **Disadvantages:** Cap and trade will place some operating cost pressure on energy-

intensive, trade-exposed industries that rely on natural gas for energy input, potentially causing a shift in capital and cost pass-through. May draw investment away from other goals, such as resiliency and new consumer demand

- **Feature:** Achieves targeted reduction in GHG
  - **Advantages:** Cap-and-trade limits are placed by legislation or the regulatory agency. These can be adjusted to reflect economic conditions, alteration in emissions reduction goals, and strategies related to the goals.
  - **Disadvantages:** Cap and trade may have a reduced impact if consumers oppose the increases in end-use costs or are unwilling to pay the additional cost
- **Feature:** Cost effectiveness
  - **Advantages:** Cap and trade is an added cost (designed to be a pass-through to end users). This approach can be transparent to regulated entities and consumers and allows the operator to select the lowest-cost alternative. Relies on a price/demand response to promote conservation at the Industrial end use.
  - **Disadvantages:** The demand for issuance of free allowances, and the market intervention on allowance supply and price floor/ceiling, can distort cost effectiveness.
- **Feature:** Use of revenue
  - **Advantages:** Easily facilitates distribution to low-income communities or disadvantaged communities.
- **Feature:** Shifting the location of GHG emissions
  - **Advantages:** Potential risk of carbon leakage impacts on trade-exposed industries is more easily managed compared with other program designs through, for example, a carbon border adjustment mechanism or free allowances in the programs.
  - **Disadvantages:** Potential risk of carbon leakage impacts on trade-exposed industries can be more challenging to manage solely through free allowances later in the program when deeper emissions reductions would be required.

d. Carbon Tax

- Fixed cost added to the price of hydrocarbon fuels and/or to the carbon emissions used in the manufacture of goods; no target metric for reductions—i.e., cost is fixed, emissions vary
- **Feature:** Sets a clear, fixed cost to emit CO2e, allowing investment decisions that reduce or avoid that cost; predictability, simplicity, and ability to implement, all while still leveraging market forces to drive cost-effective abatement
  - **Advantages:**
    - Uniform and predictable cost of GHG emissions across the economy in each tax period
    - Relatively low administrative complexity and cost due to existing tax/excise structures
    - Fixed and/or predictable pricing is easy for regulated entities and consumers to understand.
    - Predictable, immediate source of revenue in each tax period for the government to aid planning and efficient allocation of resources, which can be used to further reduce emissions or achieve other policy priorities
    - A gradually increasing carbon tax may be more cost effective in reaching a long-term target than a volatile allowance price.
  - **Disadvantages:**
    - Taxes set by and subject to change by the political system; a single tax rate can impact disparate end-use sectors very differently
    - Difficult and politically unpopular to introduce and agree upon
    - Focus may be shifted to revenue generation and fiscal policy rather than environmental policy, especially during times of lower economic output
    - Difficult to compensate industries most affected by foreign competition without impacting price signal
    - Opposition due to lack of cap on emissions, unless linked directly to the

emissions reduction target though a price escalator

- **Feature:** Cost effectiveness
  - **Advantages:** In addition to incentivizing emissions reduction investments, also directly incentivizes demand reduction but allows a company to select the lowest-cost alternative
- **Feature**: Shifting the location of GHG emissions
  - **Advantages:** Potential risk of carbon leakage impacts on trade-exposed industries is more easily manageable within the program, compared with other market-based approaches, e.g., through the use of a carbon border adjustment mechanism.

e. Incentives Applied to Capital and Operations Expenses

- **Feature:** Reducing the cost of capital for GHG emissions investments
  - **Advantages:** Lower capital costs improve the investment decision on a dollar/ton emissions reduction, thus incentivizing more and faster investments.
  - **Disadvantages:** Tax incentives on capital are subject to very specific and proscriptive rules, which need to foresee every possible action by an operator; tax benefits through deductions and credits reduce tax revenues
- **Feature:** Incentive to reduce operations expenses
  - **Advantages:** The MERP fee, which the U.S. IRA refers to as a waste emissions charge, is an operating expense that can be reduced through methane emissions reduction. The DOE and EPA grant funding to help operators mitigate emissions from marginal conventional wells is the financial incentive piece of the IRA MERP.
  - **Disadvantages:** Depends on the accurate quantification of emissions source, quantity, and rate. Methane emitters are both regulated and, through the IRA MERP, pay a fee. Generally, efficiency would dictate to either regulate or charge a fee—not both.

f. Incentives at the Corporate Level

- **Feature:** Corporate social responsibility considerations
  - **Advantages:** Voluntary commitments to targets, such as GHG intensity, absolute emissions, methane intensity, flaring intensity, or net zero by a certain date, can provide individual companies pathways to emissions reduction outside of a mandated regulatory framework.
  - **Disadvantages:** Indirect incentive depends on civil society to work alongside and outside of regulatory efforts. Naming-and-shaming for failure to achieve generates adversarial relationships.
- **Feature:** Capital market connections to GHG emissions reduction
  - **Advantages:** Provides an additional, complementary market mechanism to reduce GHG emissions; uses the influence of capital markets and financial institutions to incentivize financed companies
  - **Disadvantages:** Essentially using the corporate social responsibility obligations of the financial institutions to influence the financial institution's natural gas supply chain clients.

FINDING 18: **Multiple examples of market-based mechanisms exist that have been demonstrated to effectively incentivize GHG emissions reductions. These represent a diverse set of policy instruments cutting across a wide range of different markets and jurisdictions.**

RECOMMENDATION 17: ***The NPC recommends federal and state governments adopt market-based mechanisms to generate incentives for investment in GHG emissions reductions throughout natural gas supply chains. These mechanisms should include oil and gas industry-specific mechanisms focused on methane emissions and economy-wide mechanisms that address carbon dioxide and other GHGs.***

C. Differentiating Low GHG Intensity Gas

The development of a credible, differentiated low-emissions natural gas market, involving the payment of green premiums by utilities or customers, would serve as an effective voluntary market mechanism in incentivizing natural gas operators to reduce emissions beyond regulatory requirements. The differentiated gas market is currently constrained by state-level PUC low-cost mandates that generally prohibit utilities from paying premiums for differentiated gas, despite, in many instances, those same utilities and their customers desiring to use their purchasing power to incentivize emissions reductions across their natural gas supply chains. While a limited number of states have adopted, or are considering, legislation designed to support the development of a differentiated natural gas market, there are generally few regulatory or policy structures that enable the pass-through of differentiated gas premiums necessary to encourage the development of the differentiated gas market as a market mechanism to incentivize emissions reductions.

It is important to note that the differentiated gas market is, at present, entirely voluntary. The ability to value the lower CI of differentiated gas can play a valuable role in incentivizing operators to pursue emissions reductions initiatives that go beyond regulatory requirements. If structured properly, a market incentive would encourage both lower-emissions operators to continue to reduce emissions and higher-emissions operators to reduce emissions to the point where they could participate in the differentiated gas market.

There are several reasons, beyond low-cost mandates, why state PUCs have been hesitant to approve the payment by utilities and pass-through to customers of differentiated gas premiums. Primary among those reasons are: (1) the lack of a recognized certification standard or confusion with existing certification programs and, (2) a lack of assurance that the purchase of differentiated gas will help reduce emissions. These concerns are partly the result of the fact that initial natural gas certification programs were more investor-focused than market-focused. Those early programs also differentiated operators more broadly, based on a variety of criteria (other than GHG emissions), with EPA Subpart W GHG Reporting Program data[58] or methane management programs and technology deployment serving as a proxy for measured and verified emissions intensities. Additionally, most natural gas certification programs focus almost exclusively on the production sector and largely do not account for emissions across the midstream sector, which are associated with the gathering, boosting, processing, transmission, and delivery of natural gas. Standardization of protocols and methodologies is likely to increase as the differentiated gas market and its associated certification programs continue to evolve to focus more narrowly on quantitative, measurement-informed emissions intensities and carbon accounting across the full natural gas supply chain, rather than relying on qualitative criteria and emissions factors. This, in turn, will drive greater confidence in the role of differentiated gas as a market mechanism to incentivize emissions reductions across natural gas supply chains.

Governments, nongovernmental organizations, academic institutions, and industry coalitions are working to develop sets of principles for the measurement, reporting, and verification of emissions across natural gas supply chains. These efforts include the OGMP 2.0 framework,[59] the Climate and Clean Air Coalition,[60] and the Energy Emissions and Modeling Data Lab (EEMDL),[61] an initiative of three U.S. universities—the University of Texas in Austin, Colorado State University, and the Colorado School of Mines—along with the Oxford Institute for Energy Studies in the United Kingdom. Key among these efforts is the recent announcement by DOE of the formation of an international working group of global gas importing and exporting countries that is exploring the development of a MMRV framework for "methane, carbon dioxide, and other GHG emissions that occur during the production

58 EPA. "Greenhouse Gas Reporting Program, Subpart W – Petroleum and Natural Gas Systems." Updated May 6, 2024. https://www.epa.gov/ghgreporting/subpart-w-petroleum-and-natural-gas-systems.

59 U.N. Environment Programme. "The Oil & Gas Methane Partnership 2.0." n.d. https://www.unep.org/topics/energy/methane/international-methane-emissions-observatory/imeo-action/methane-alert-and.

60 U.N. Environment Programme. "Climate and Clean Air Coalition." n.d. https://www.ccacoalition.org/.

61 Energy Emissions Modeling and Data Lab. n.d. https://www.eemdl.utexas.edu/.

gathering, processing, transmission, liquefaction, transport and distribution of natural gas." According to its founding principles, the working group plans to convene throughout 2024 with the goal of "(1) identifying key elements of a MMRV framework that could enable credible verification of methane, carbon dioxide, and other GHG emissions across the international natural gas supply chain, (2) building on the strengths and weaknesses of existing certification and reporting approaches already used in the international marketplace, and (3) addressing gaps and harmonizing approaches to safeguard integrity, enhance credibility, and improve accuracy, completeness, and transparency of reported emissions." This effort, which is likely to take learnings from OGMP 2.0, EEMDL and other such initiatives, has the potential to serve as a roadmap and coalescing force for the domestic differentiated gas market in further enhancing standardization across certification programs and, in so doing, reduce the confusion in the differentiated gas market.

To further encourage PUCs to approve the payment for differentiated gas by utilities and pass-through to customers (whether mandatory or voluntary) of differentiated gas premiums, it is important for transactions to be structured in a manner, and with appropriate metrics, such that premiums incentivize ongoing emissions reductions. There are several ways this can be accomplished. For example, transactions can be structured such that the payment of a premium increases as emissions are reduced. Or ongoing payment of an established premium could only be permitted if emissions continue to be reduced in accordance with a sliding scale. In the first instance, the seller and buyer could agree to certain tiers of CH_4 or CO_2e intensity with the differentiated gas premium increasing as each tier is achieved. In the second instance, the seller and buyer could agree to a floor for a stated premium that could continue to become more stringent over an agreed upon period such that if the seller does not achieve the floor, no premium is payable. Both transactional structures require robust, timely, and granular measurement and verification of emissions intensity such that the delivery of gas each period is correlated as closely as possible to the emissions intensity for that gas over the same period. In either of these instances, PUCs would have greater assurance that any green premiums paid by utilities and passed through to customers would be used to fund emissions reduction initiatives at a transparent cost to customers. To the extent that green premiums are passed through to low-income residential customers, these premiums need to be structured to help ensure that these households' energy burden is not increased. For instance, energy assistance programs that help low-income families cover their energy bills could be expanded to cover increased costs due to the differentiated gas premium pass-through.

The differentiated gas market is still developing but transactions generally follow two formats: (1) bundled, in which environmental attributes are correlated to, and sold together with, physical gas and (2) unbundled, in which environmental attributes are not correlated to and sold separate from physical gas. Critical to both types of transaction formats is the need for, and use of, registries to track and retire environmental attributes. Registries help provide confidence to buyers that environmental attributes are securely transferred and accurately accounted for to avoid any concerns with double counting. Several registries already exist, although the interoperability between registries remains a challenge. The lack of interoperability is an impediment to market development, because environmental attributes are generally only compatible with certain registries, making the transfer of environmental attributes between registries complex and limited. Increasing interoperability between registries through, for example, the utilization of blockchain-backed distributed ledger technology, would be beneficial to the ongoing development of the differentiated gas market.

As a practicable solution, the NAESB, which has experience with facilitating and supporting commercial transactions and ensuring interoperability across multiple industry platforms, is in the process of developing a registry. Utilizing a NAESB registry for differentiated gas transactions could allow for greater transparency and efficiency in contracting. Additionally, by using the NAESB addendum to the base contract for the sale and purchase of certified natural gas, the NAESB registry would allow for the seamless sharing of information about environmental attributes. The

NAESB registry will differ from existing registries in that the NAESB registry will not offer tracking capabilities for environmental attributes associated with other registries. However, it still would help to provide a streamlined transactional pathway by assuring transparency and consistency from seller to buyer in the differentiated natural gas market.

While the market is still in the early stages of development, differentiated gas can serve as an impactful market mechanism and valuable complement to command-and-control regulations by encouraging voluntary emissions reductions across the natural gas supply chain that go above and beyond regulatory requirements. Essential to this are the development of a recognized measurement or certification standard for differentiated gas, appropriate metrics or transactional structures to correlate the payment of green premiums to emissions reductions, and either greater interoperability between registries or the emergence of a lead registry to streamline tracking and retirement of environmental attributes. If the foregoing can be accomplished, then differentiated gas certification programs have the potential to flourish as a voluntary market mechanism for emissions reductions by providing a financial incentive for operators to voluntarily invest in, or design and operate facilities with, enhanced emissions control technologies that may not otherwise be financially viable or required by regulation.

FINDING 19: **Today there are few regulatory or other policy structures (excluding cap and trade and carbon taxes) in place that enable the pass-through of incremental value associated with lower GHG intensity natural gas. While certified gas markets and price formation around certified natural gas are still developing, they are limited in scale, without a material price premium, and lack uniform, measurement-based criteria to justify differentiation.**

RECOMMENDATION 18: ***The NPC recommends standard-setting bodies develop mechanisms to enable utilities, gas marketers, and consumers of natural gas to differentiate lower GHG intensity natural gas, specifically providing recognized standards, frameworks, and metrics for buyers and sellers to incorporate into gas transaction contracts. These standards should be measurement-based where feasible.***

D. Enhancement of Societal and Community Benefits

The following section discusses societal and community considerations for select mitigation strategies. High-impact, high-feasibility recommendations are analyzed in detail for societal considerations and impacts (SCI), as these represent the most likely paths to reduce GHG emissions from the natural gas supply chain while supporting the goals of net zero emissions and U.S. energy security.

1. Regulatory Consistency and Harmonization

Several findings and recommendations previously discussed in this report speak to the realities of the reporting under the existing GHG emissions reporting frameworks. There is a lack of consistency among state and federal agencies, including programs that are administered through the EPA, Pipeline and Hazardous Materials Safety Administration, and BLM; this can include duplicate or contradictory requirements and reporting periods.

Regulatory harmonization enables more effective regulation by supporting the right timeline and process for engagement. Clarity surrounding planned construction related to GHG reductions in the natural gas supply chain, as well as reported data from facility operations, allows the public a better opportunity to assess impacts to the local community through a common metric (i.e., a single, harmonized, GHG emissions metric). This can improve the community engagement process and enable more effective communication between regulators, industry, and the public.

2. Infrastructure and Permitting

Reliable infrastructure and timely and efficient permitting are necessary to ensure GHG

emissions are minimized in the natural gas supply chain, both to reduce GHG emissions from existing production volumes and as natural gas production and exports from the United States increase. The lack of pipeline capacity in many oil and gas basins has led to an increase in venting and flaring and a correlated increase in GHG emissions. New pipeline infrastructure will be required to reduce GHG emissions associated with the natural gas supply chain. This subject was extensively evaluated, with many recommendations for improvement to the permitting process, in the 2019 NPC report *Dynamic Delivery*.[62]

Pipeline projects have received growing levels of legal challenges and general opposition in gaining permits and siting approvals. Public concerns include safety, environmental impacts (including leaks and spills) and climate change, the excise of eminent domain by government or corporations, compensation, economic loss due to condemnation of property, construction-related disruptions, and general doubts about the need for a new supply of hydrocarbons. Additional concerns are related to loss of income and livelihood and general economic impacts due to competing uses for land. Community concerns or fears, particularly around environmental and health impacts, can be based on actual or perceived dangers.

All communities will require effective engagement as they may not support additional natural gas infrastructure development unless there are clear societal benefits and local incentives to such projects.

Community benefits can take many forms, including opportunities or support for local businesses or industries that rely on energy. Community benefit plans can also be one effective mechanism to convey benefits (particularly when projects are larger or involve higher levels of capital investment). Other benefits to pipeline infrastructure include reduced air pollution due to the displacement of trucking and loading/unloading operations and the elimination of fugitive methane emissions from portions of the supply chain related to storage and trucking.

If permitting processes are streamlined, care should be taken to ensure community engagement is maintained and that the both the benefits and trade-offs of infrastructure are clearly communicated. While timely and efficient permitting is needed, it should be recognized that best practice community engagement can also require time and resources. When implemented though, community engagement best practices can also help project developers avoid or mitigate adverse impacts on communities, particularly disadvantaged ones, over the life of a project or activity.

3. Carbon Capture and Storage (CCS)

CCS of natural gas is an emerging area with multiple demonstration projects to test technologies along the natural gas supply chain. Given the diluted carbon emissions streams from natural gas-fired turbines, the technology for concentrating and removing carbon from the emissions is more complicated. However, the industry is now making progress that may be supported by pending legislation to compensate for the lack of carbon pricing. This section does not intend to analyze the SCI implications of all CCS technologies or opportunities, because regional and technological limitations mean that the feasibility of projects is largely dependent on these factors. Deployment of CCS was extensively evaluated, with many recommendations for wider adoption, in the 2019 NPC report *Dual Challenge*.[63]

Considering the SCIs of lowering GHG emissions from the natural gas supply chain, CCS could provide a path to sustaining economic opportunity in regions that have historically produced natural gas and relied on natural gas revenue. CCS can mitigate a large portion of the emissions from the natural gas supply chain. The success of these efforts will largely depend upon industry actions and community support of such projects. Additionally, the capture of fugitive methane emissions from the supply chain reduces local air quality impacts, as previously discussed in this report. Therefore, IRA and the IIJA both have

62 National Petroleum Council. "Dynamic Delivery: America's Evolving Oil and Natural Gas Transportation Infrastructure." 2019. https://dynamicdelivery.npc.org/.

63 National Petroleum Council. "Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage." 2019. https://dualchallenge.npc.org/.

significant incentives to foster the development of technology and installation of large-scale CCS projects.

When CCS is applied at LNG liquefaction facilities, the benefits must be considered along with community impacts of adding additional infrastructure to the facility site. Note that CCS efforts could also impact EPA-regulated air emissions from LNG plants that include volatile organic compounds, nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), and particulate matter.

4. Measurement Technology Advancement and Community Data Sharing

Continued rapid progress in methane emissions measurement is anticipated. Chapter 3 makes specific recommendations for tracking this progress and for facilitating the rapid deployment and use of these technologies in regulatory compliance. Key to the implementation of these recommendations will be ensuring that regulations developed to reduce methane emissions across the natural gas supply chain remain flexible enough to promote the adoption of new or improved technologies. Quantification of intermittent emissions should focus on rapid detection and order-of-magnitude quantification, allowing operators to respond promptly to find and eliminate intermittent emissions.

Rapid quantification and reporting are key drivers for public transparency in reporting methane emissions. Measurement technologies, while not the sole enabler of GHG reductions, will invariably drive more accurate and precise reporting, which provides fence-line communities data for evaluating benefits and trade-offs of emissions reduction technologies that may be utilized in the natural gas supply chain in their community.

E. International Recognition for Lower Emissions Intensity LNG

One opportunity for economic community benefits from GHG emissions reductions involves the development of facilities such as the Methane Emissions Technology Evaluation Center (METEC)[64] located at the Colorado State University (CSU) Energy Institute in Fort Collins, Colorado. This facility has provided an opportunity for testing and validation of new methane detection and quantification equipment. Construction of the facility was part of an estimated $7 million DOE investment in the Energy Institute at CSU and has provided both economic development and regional expertise to support testing of detection equipment necessary for measurement of methane emissions reductions. Through a recent $50 million partnership, METEC partnered with the University of Texas–Austin to tackle the challenge of oil and gas methane emissions accounting. This partnership, the EEMDL, can serve as a model in leveraging regional and national expertise to further economic development and affirm support for continued production of energy, while simultaneously reducing GHG emissions.

The next several subsections discuss the SCI from LNG, and ways to recognize the benefits and address the impacts.

1. Domestic Economic Benefits of Global Exports

LNG exports from the United States create economic opportunities in the communities in which export terminals are located, and throughout the natural gas supply chain. These benefits include direct and indirect jobs, new investment and capital expenditures that support tax revenue and other spending in local economies around the country. The U.S. trade deficit may benefit from selling significant quantities of natural gas as exports through the international markets. This would positively impact the overall balance of trade and economic stability of the United States.

2. Combating Worldwide Energy Poverty

It is estimated that nearly a billion people worldwide do not have access to electricity and billions more do not have reliable sources of power. As global populations continue to increase and developing economies continue to grow, a key challenge will be meeting the significant demand increases for energy that will accompany this type of growth.

64 Colorado State University. Methane Emissions Technology Evaluation Center (METEC). n.d. https://metec.colostate.edu/.

In many developing countries, there is still limited access to modern energy systems. It is common to find a reliance on traditional, higher-emissions fuels such as biomass, kerosene, coal, and oil, which, when used for cooking, can have adverse health impacts. LNG is a cleaner-burning fuel compared to many of the traditional alternatives, and it can serve as an energy source that supports and enables the optimal deployment of renewable power over time. The transition to natural gas could lead to significant reductions in GHG emissions and improvements in air quality, especially in developing countries.

Increased access to multiple energy options will allow countries to better meet energy needs and reduce energy poverty by ensuring a cleaner, more secure and reliable energy supply. In some cases, LNG imports will lead to more competitive energy pricing, reducing energy costs for consumers, including low-income households.

3. Benefits to Global Markets

U.S. LNG exports supply much-needed energy globally, while offering a reduced emissions pathway to consuming nations. Growing U.S. LNG exports provide substantial energy system benefits, including:

- **A lower-carbon fuel alternative to global markets.**[65] Natural gas's lower-carbon profile can drive material reductions in GHG emissions through displacement of higher-carbon fuels, most notably coal. The United States provides a compelling case study wherein national GHG emissions growth was reversed beginning in the early 2000s by the introduction of abundant natural gas from previously inaccessible sources due to improvements in shale gas technology.[66]
- **Air quality improvements in consuming markets** by reducing particulates and other emissions from coal and other fuels. Air quality is an immediate and pressing challenge in many developing economies, with major long-term implications for public health and economic development. For example, over the past decade, Beijing, China has achieved a sharp reduction in many forms of air pollution through the deployment of gas-fired electricity generation, the retirement of coal facilities, and other contributing air quality measures.[67] By providing natural gas via LNG exports, the United States can make impactful contributions to both climate and local air quality imperatives.
- **Abundant long-term energy supplies.** Abundant U.S. natural gas resources can underpin decades of energy supplies to LNG markets around the world, facilitating lasting energy security and supporting long-life energy system investments in evolving markets.[68]
- **Readily deployable and scalable energy.** Through LNG exports, natural gas can be deployed rapidly to new markets and offer energy at a scale needed to bring both energy security and timely emissions improvements. Additionally, natural gas can deliver high energy intensity where needed, particularly in urban and industrial areas.
- **Compatibility with existing natural gas distribution and demand systems,** avoiding costs and delays associated with new fuels. In many markets, existing domestic natural gas infrastructure can be leveraged with new gas imports, accelerating access to natural gas and lowering the delivered cost profile. This applies both to markets where domestic gas supplies have declined (as in parts of Europe) and newer gas markets where pipeline utilization is under capacity. Furthermore, end customers may find switching to gas is faster and less costly than measures to accommodate other fuels.

65 Mallapragada, D.S., Reyes-Bastida, E., Roberto, F., McElroy, E.M., Veskovic, D., and Laurenzi, I.J. "Life Cycle Greenhouse Gas Emissions and Freshwater Consumption of Liquefied Marcellus Shale Gas Used for International Power Generation." *Journal of Cleaner Production* 205 (December): 672–80. 2018. https://doi.org/10.1016/j.jclepro.2018.09.111.

66 Ramseur, Jonathan. "Greenhouse Gas Emissions in the U.S. Electricity Sector: Background, Policies, and Projections." Congressional Research Service. May 18, 2023. https://crsreports.congress.gov/product/pdf/R/R47561.

67 Kuang, Yunming, and Boqiang Lin. "Unwatched Pollution Reduction: The Effect of Natural Gas Utilization on Air Quality." *Energy* 273 (June): 127247. 2023. https://doi.org/10.1016/j.energy.2023.127247.

68 EIA. "Frequently Asked Questions: How Much Natural Gas Does the United States Have, and How Long Will it Last?" March 28, 2023. https://www.eia.gov/tools/faqs/faq.php?id=58&t=8#:~:text=Assuming%20the%20same%20annual%20rate.

- **Proven technologies with decades of experience.** Over a span of decades, the LNG industry has earned a proven track record of safely producing, transporting, and receiving LNG globally. Through continuous technological advancement across the supply chain, the LNG industry has developed a robust yet flexible energy system at scale to serve global energy needs.
- **Increased reliability for power systems in complement to renewables.** With high generation flexibility and rapid response capabilities, natural gas-fired plants can provide critical stability to power networks and complement the buildout of renewable energy sources.[69]
- **Flexible geographic delivery** offering better response to dynamic energy demand, with improved energy security for the global system. Since LNG is predominantly transported by ship, LNG flows can be redirected to meet emerging energy priorities. Two landmark examples are a) the LNG response to serve Japan's energy demand following the shuttering of reactors after the Fukushima events in 2011 and b) the redirection of LNG supplies to Europe during the Ukraine/Russia conflict (2022+). Both cases demonstrated the value of flexible LNG systems in addressing critical, unforeseen energy challenges.[70]
- **Economic vitality for both producing and consuming nations,** with significant U.S. local and regional benefits over the life of LNG projects. Through major capital investments, long operating lifespans, and integration with upstream and downstream economies, LNG drives lasting, long-term economic gains across the globe. U.S. LNG projects built to date brought investment on the order of U.S.$80 billion; a further $100 billion of investment is possible from projects under consideration or actively being constructed.[71] One study estimates that the cumulative economic contribution from investment in LNG production is likely to be between $1.6 and $3.3 trillion through 2050, generating between 7.3 and 15.5 million jobs.[72] These gains accrue locally to the producing and liquefaction regions and communities, and more broadly to U.S. industry as a whole, all while stimulating significant government revenue.

4. Global Emissions Reductions

Although new LNG production might increase carbon emissions in the United States, the global net impact could reduce global emissions through the displacement of coal-fired generation and liquids. For U.S. LNG displacement of coal generation in China, researchers estimated a 47%–57% reduction in global GHG emissions intensity, from sourcing to power generation.[73] The scale of U.S. LNG exports can therefore make a material and lasting contribution to global GHG emissions reduction efforts.

The U.S. upstream gas supply chain is already one of the world's more regulated industries. Current and proposed regulations are expected to continue to reduce domestic GHG emissions intensity across the natural gas supply chain. In addition, low-carbon technologies, ranging from electrification of compression and liquefaction to CCS, provide emerging pathways to reduce the CI of U.S.-sourced natural gas and LNG. These upstream initiatives can make a valuable contribution to decarbonization efforts globally and help maintain the competitiveness of U.S. energy exports in international markets.

In January 2024, the DOE announced a temporary pause on authorizations for pending applications for new LNG export projects, as it conducts

69 Mac Kinnon, M.A., Brouwer, J., and Samuelsen, S. "The Role of Natural Gas and Its Infrastructure in Mitigating Greenhouse Gas Emissions, Improving Regional Air Quality, and Renewable Resource Integration." *Progress in Energy and Combustion Science* 64 (January): 62–92. 2018. https://doi.org/10.1016/j.pecs.2017.10.002.

70 IEA. "Gas Market Report, Q1-2024." 2024. https://iea.blob.core.windows.net/assets/601bff14-5d9b-4fef-8eccd7b2e8e7449a/GasMarketReportQ12024.pdf

71 Harrison, Sean. "Third Wave U.S. LNG: A $100 Billion Opportunity." Wood Mackenzie. February 22, 2023. https://www.woodmac.com/news/opinion/third-wave-us-lng/.

72 Williams Companies. "Calculating the Benefits of US LNG Exports." May 2, 2018. https://www.williams.com/2018/05/02/calculating-the-benefits-of-us-lng-exports/.

73 Roman-White, S.A., Littlefield, J.A., Fleury, K.G., Allen, D.T., Balcombe, P., Konschnik, K.E., Ewing, J., Ross, G.B., and George, F. "LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting." *ACS Sustainable Chemistry & Engineering* 9 (32): 10857–67. 2021. https://doi.org/10.1021/acssuschemeng.1c03307.

a national interest assessment.[74] This late breaking policy announcement was not able to be fully considered and analyzed by the NPC, although some of the insights from this report should be germane to the national interest assessment process. Some important considerations, like unintended consequences on global supply and demand balance and investment certainty for projects in the U.S., are outside the scope of this NPC work, but would be important opportunities for further industry consultation by DOE and inputs into a consequential LCA. As described in this section, there are numerous benefits to U.S. LNG exports, including GHG and air quality benefits in consuming markets to the degree that higher-emissions fuels are displaced, energy security benefits to allies, and an abundant resource base for providing scalable energy supplies globally. This NPC report also provides recommendations for addressing some of the key current trade-offs for U.S. LNG exports, including an evaluation of SCI and community engagement best practices, simplified tools for estimating supply chain GHG emissions intensity as part of MMRV programs, pathways for significant methane reductions in the natural gas supply chain, including the suite of federal methane regulations across several agencies, and research, development, demonstration, and deployment opportunities for reducing supply chain carbon dioxide emissions, including from liquefaction. The NPC hopes that this information is useful to DOE as part of the national interest assessment approval process.[75]

FINDING 20: **The growth in U.S. LNG exports can contribute to GHG emissions reductions globally but may result in an increase in GHG emissions within U.S. natural gas supply chains. To mitigate the growth in these emissions, investments in lower carbon technologies will need to be recognized and incentivized.**

74 DOE. "DOE to Update Public Interest Analysis to Enhance National Security, Achieve Clean Energy Goals, and Continue Support for Global Allies." January 6, 2024. https://www.energy.gov/articles/doe-update-public-interest-analysis-enhance-national-security-achieve-clean-energy-goals.

75 DOE. "DOE to Update Public Interest Analysis to Enhance National Security, Achieve Clean Energy Goals, and Continue Support for Global Allies." January 6, 2024. https://www.energy.gov/articles/doe-update-public-interest-analysis-enhance-national-security-achieve-clean-energy-goals.

RECOMMENDATION 19:

The NPC recommends:

- The U.S. federal government should continue to leverage U.S. LNG exports to promote energy security and the potential for global GHG reductions.
- The U.S. federal government should continue to work toward international recognition of the lower emissions intensity of U.S. exported products, including LNG.

IV. CONCLUSION

The U.S. natural gas supply chain consists of a diverse set of producers, transporters, and distribution systems, including LNG. As discussed in Chapter 1, abundant, affordable natural gas is the largest source of primary energy production in the United States. It will continue to play a crucial role in energy security and an important role in economic security beyond 2050 under all EIA scenarios. (Note that the EIA does not currently provide a Net Zero by 2050 scenario, as EIA only recognizes existing policies and regulations.)

Reducing GHG emissions from the natural gas supply chain requires many different actions by government and the private sector, including *direct actions* to reduce emissions, shifts in energy usage within the supply chain, and capital deployment for CI reduction. This also requires *enabling actions*, including building confidence in emissions reporting and accounting, differentiating lower CI gas, building trust and acceptance of natural gas through stakeholder engagement, and capacity building within the industry.

Reducing GHG emissions requires short- and long-term actions. In the short term, these include actions already in process or ones that can be quickly initiated (in the next two years). In addition, near-term foundation building may be implemented to enable future high-potential reduction that faces time or feasibility challenges. Scaling impact over several years requires industry to build on the short- and near-term actions to maximize emissions reductions; a key component of scaling impact is the shift in fuel supply for the natural gas supply chain toward lower-emitting

energy sources, including electrification, energy efficiency, CCS, and hydrogen.

Significant actions can, and should, be taken by operators within the supply chain. Sharing these widely across operators, and providing market-based incentives to implement them, will greatly speed and scale reductions across operators of all sizes. Tools such as the MAC curve can assist operators in deploying skills and capital to the most cost-effective emissions abatement projects.

Scenarios are an effective and well-proven method of evaluating potential energy consumption; however, many scenarios are global-scale or continental-scale and do not provide sufficient granularity (at the level of supply chain elements) to be useful in determining future flows for specific supply chains. EIA scenarios were used in this study due to their granularity, and recommendations are made for ways to improve the usefulness of these scenarios in GHG emissions reduction planning.

Three pathways to future emissions reduction are analyzed in this study: Existing Policies, Continued Reductions, and Technology, Innovation, and Policy (TIP). The last pathway for 2050, TIP, results in significant reductions in methane and carbon dioxide emissions through a combination of regulatory and market mechanisms (for methane), as well as deployment of emissions mitigation technologies for carbon dioxide (reduced CI power generation, electrification, CCS, and LCI hydrogen).

The study evaluates an array of market mechanisms, showing examples of where they have been put in place and discussing the advantages and disadvantages of each. The study does not attempt to select one preferred market mechanism, however, one market mechanism, differentiated natural gas, receives extensive analysis on both the required enablers (accurate MMRV, contractual structures) and potential regulatory implementation.

Building on the importance of MMRV, the study evaluates the importance of international recognition of reductions in CI of U.S. natural gas, in particular for LNG cargoes, and restates the crucial importance of LNG for U.S. energy security. Throughout the study, relevant SCI aspects of high-impact and high-feasibility recommendations are discussed in Chapter 2, as these represent the most likely paths to emissions reductions in the natural gas supply chain. These recommended projects, activities, and policies should avoid or mitigate adverse impacts on communities, particularly the disadvantaged, while maximizing the effectiveness of community benefits that can flow from these actions. And they can only be implemented through meaningful stakeholder engagement and community support.

APPENDICES

Appendix C:
Societal Considerations and Impacts

Appendix D:
Detection and Quantification of GHG Emissions

Appendix E:
GHG Life Cycle Assessment for Natural Gas and LNG

Acronyms and Abbreviations

Description of Additional Materials

Appendix C

SOCIETAL CONSIDERATIONS AND IMPACTS

I. HISTORY AND EVOLUTION OF TODAY'S COMMUNITY AND ENVIRONMENTAL JUSTICE ISSUES

Note: This section has been jointly developed by the Societal Considerations and Impacts (SCI) Task Group 5 for the National Petroleum Council's (NPC) Charting the Course *greenhouse gas emissions study and* Harnessing Hydrogen *hydrogen energy study.*

A. Introduction

From the outset, environmental justice (EJ) advocates have sought remedies for the disproportionate impact borne by marginalized communities due to social policies (i.e., redlining, blockbusting, predatory loans, restrictive covenants)[1, 2] or land use planning (i.e., racial zoning ordinances, urban redevelopment or gentrification, unequal enforcement of zoning, and environmental laws).[3, 4] These concepts were described as environmental racism, a form of institutional discrimination that involves a complex system of institutionalized policies, practices, and directives that differentially impact or disadvantage (intentionally or unintentionally), individuals, groups, or communities based on race.[5] In many cases, this environmental racism manifests as industrial facilities and their associated impacts being positioned disproportionately in minoritized neighborhoods.[6] Dr. Robert Bullard, often called the "father of environmental justice," described it succinctly:

> *"Whether by conscious design or institutional neglect, communities of color in urban ghettos, in rural poverty pockets, or on economically impoverished Native American reservations face some of the worst environmental devastation in the nation."*[7]

The mainstream environmental movement of the 1960s and 1970s heavily focused environmentalists' efforts on the natural world.[8] It was not until intersectional environmentalism and EJ came into the picture in the 1980s that built environments were fully integrated into advocacy

1 Rothstein, Richard. 2015. "The Making of Ferguson." *Journal of Affordable Housing & Community Development Law* 24 (2): 165–204. https://www.jstor.org/stable/26408162.

2 Holland, Joshua. "How a Century of Racist Policies Made Ferguson into a Pocket of Concentrated Despair." October 27, 2014. https://billmoyers.com/2014/10/27/century-racist-policies-created-ferguson/.

3 EPA. "Addressing Community Concerns: How Environmental Justice Relates to Land Use Planning and Zoning." 2003. https://www.epa.gov/sites/default/files/2015-02/documents/napa-land-use-zoning-63003.pdf.

4 EPA. "Equitable Development and Environmental Justice." https://www.epa.gov/environmentaljustice/equitable-development-and-environmental-justice.

5 Holland, Joshua. "How a Century of Racist Policies Made Ferguson into a Pocket of Concentrated Despair." October 27, 2014. https://billmoyers.com/2014/10/27/century-racist-policies-created-ferguson/.

6 "The Complicated History of Environmental Racism." University of New Mexico. August 4, 2020. https://news.unm.edu/news/the-complicated-history-of-environmental-racism.

7 EPA. 2019. "Environmental Justice Timeline." https://www.epa.gov/environmentaljustice/environmental-justice-timeline.

8 University of Minnesota, Duluth. "Environmentalism vs. Environmental Justice." 2020. https://sustainability.d.umn.edu/environmentalism-vs-environmental-justice.

for environmental protections.[9, 10, 11] EJ advocates expanded the concept of the environment in the 1980s to include the places where people "live, work, play, go to school, as well as the physical and natural world,"[12] as a means of uniting the physical and cultural environments—and their respective justice movements—under integrated and collaborative banners.[13]

The EJ movement's birthplace is considered by many to be the Warren County, N.C., polychlorinated biphenyl (PCB) landfill battle in 1982. Civil rights organizers in North Carolina protested a proposed landfill in a county comprised of predominately Black American communities. The project posed environmental risks because a shallow water table at the landfill site created opportunity for potential groundwater-soil-waste interactions. Because issues of racial, economic, and social justice had nexus with issues of environmental risks, the Warren County collective actions highlighted a previously unconsidered aspect of mainstream environmentalism: whether minorities and poor communities were facing environmental harms and risks at a greater rate than other groups in society.[14] The project proceeded and ultimately more than 120 million pounds of PCB contaminated the soil in the landfill. Subsequently, scholars and community organizers shifted focus from individual protest actions, instead documenting instances of perceived environmental racism and the correlation between pollution, race, and poverty.[15, 16, 17]

Several landmark studies starting in the 1980s[18] and continuing today[19, 20, 21] seek to establish correlations, and, where possible, hypothesize causation[22] for the economic, environmental, and social factors contributing to environmental racism.[23, 24,

9 University of Minnesota, Duluth. "Environmentalism vs. Environmental Justice." 2020. https://sustainability.d.umn.edu/environmentalism-vs-environmental-justice.

10 University of Washington, College of the Environment. "Climate Justice and Sustainability." https://environment.uw.edu/about/diversity-equity-inclusion/climate-justice-sustainability/.

11 *Environmental Justice and Environmentalism: The Social Justice Challenge to the Environmental Movement*. 2007. The MIT Press. https://direct.mit.edu/books/edited-volume/4413/Environmental-Justice-and-Environmentalism.

12 Schweizer, Errol. "Environmental Justice: An Interview with Robert Bullard." *Earth First! Journal.* July 1999.

13 Schweizer, Errol. "Environmental Justice: An Interview with Robert Bullard." *Earth First! Journal.* July 1999.

14 Mohai, P., Pellow, D., and Roberts, J.T. 2009. "Environmental Justice." *Annual Review of Environment and Resources* 34 (1): 405–30. https://doi.org/10.1146/annurev-environ-082508-094348.

15 Bullard, Robert. 1994. "Journal of Civil Rights and Economic Development." *The Legacy of American Apartheid and Environmental Racism.* https://scholarship.law.stjohns.edu/cgi/viewcontent.cgi?article=1460&context=jcred.

16 Bullard, Robert D. 2003. "Confronting Environmental Racism in the 21st Century." *Race, Poverty & the Environment* 10 (1): 49–52. http://www.jstor.org/stable/41554377.

17 Bullard, Robert D. 2001. "Environmental Justice in the 21st Century: Race Still Matters." *Phylon (1960-)* 49 (3/4): 151. https://doi.org/10.2307/3132626.

18 Commission for Racial Justice, United Church of Christ. 1987. "Toxic Wastes and Race in the United States: A National Report on the Racial and Socio-Economic Characteristics of Communities with Hazardous Waste Sites." https://new.uccfiles.com/pdf/ToxicWastes&Race.pdf.

19 U.S. Government Accountability Office. "GAO-19-543, Environmental Justice: Federal Efforts Need Better Planning, Coordination, and Methods to Assess Progress." *GAO Highlights.* September 2019. https://www.liebertpub.com/doi/10.1089/env.2020.0054.

20 Kojola, Erik and David N. Pellow. 2021. "New Directions in Environmental Justice Studies: Examining the State and Violence." *Environmental Politics* 30 (1-2): 100-118. https://doi.org/10.1080/09644016.2020.1836898.

21 Hendricks, Marccus D. and Shannon Van Zandt. 2021. "Unequal Protection Revisited: Planning for Environmental Justice, Hazard Vulnerability, and Critical Infrastructure in Communities of Color." *Environmental Justice* 14 (2). https://doi.org/10.1089/env.2020.0054.

22 Wolverton, Ann. 2009. "Effects of Socio-Economic and Input-Related Factors on Polluting Plants' Location Decisions." *The B.E. Journal of Economic Analysis & Policy* 9 (1). https://doi.org/10.2202/1935-1682.2083. https://ideas.repec.org/a/bpj/bejeap/v9y2009i1n14.html.

23 United Church of Christ—Commission for Racial Justice. "Toxic Wastes and Race in the United States: A National Report on the Racial and Socio-Economic Characteristics of Communities with Hazardous Waste Sites." 1987. Reproduced from the UCC archives. https://new.uccfiles.com/pdf/ToxicWastes&Race.pdf.

24 Kojola, Erik, and David N. Pellow. 2020. "New Directions in Environmental Justice Studies: Examining the State and Violence." *Environmental Politics* 30 (1-2): 100-118. *https*://doi.org/10.1080/09644016.2020.1836898.

[25, 26] Early studies found that decisions on industrial development were often rationalized when it came to socioeconomic factors. However, this can cause timing and cause-and-effect problems, leading to erroneous conclusions about unfair treatment of residents in areas with industrial development. This became known colloquially as the Chicken and the Egg debate: Which came first—the facilities that were sited or the communities that were/would be disproportionately impacted?[27, 28, 29, 30, 31, 32, 33] Wolverton (2009) noted: "When plant location is matched to current socioeconomic characteristics, results are consistent with what the environmental justice literature predicts: race is significantly and positively related to plant location, while income is significantly and negatively related to plant location. When plant location is matched to socioeconomic characteristics at the time of siting, empirical results suggest that race is no longer significant, though income is still significantly and negatively related to plant location."[34] This change might be due to people relocating or other socioeconomic factors over time.[35,36] There is, however, a strong correlation between racial discrimination and siting[37, 38, 39, 40] found in the literature.[41]

Scholars have argued that environmental injustices happen because of the way racial groups are distributed across areas.[42, 43] Hundreds of studies conclude that, in general, ethnic minorities,

25 Hendricks, Marccus D., and Shannon Van Zandt. 2021. "Unequal Protection Revisited: Planning for Environmental Justice, Hazard Vulnerability, and Critical Infrastructure in Communities of Color." *Environmental Justice* 14 (2): 87–97. https://doi.org/10.1089/env.2020.0054.

26 Wolverton, Ann. 2009. "Effects of Socio-Economic and Input-Related Factors on Polluting Plants' Location Decisions." *The B.E. Journal of Economic Analysis & Policy* 9 (1). https://doi.org/10.2202/1935-1682.2083.

27 Mohai, Paul, and Robin Saha. 2015. "Which Came First, People or Pollution? Assessing the Disparate Siting and Post-Siting Demographic Change Hypotheses of Environmental Injustice." *Environmental Research Letters* 10 (11): 115008. https://doi.org/10.1088/1748-9326/10/11/115008.

28 Williams, Kirsten. 2022. "The Impact of Foresight: Reframing Discriminatory Intent to Properly Remedy Environmental Racism." *Houston Law Review* 59 (5): 1231–61. https://houstonlawreview.org/article/36549-the-impact-of-foresight-reframing-discriminatory-intent-to-properly-remedy-environmental-racism.

29 "Zhang, Ruohao. 2023. "Behind Environmental Injustice: Disparate Siting Industries and Post-siting Demographic Transformation." Presented Friday, January 6, 2023, at the Environmental Justice and Inequality paper session at the American Economic Association Conference in New Orleans, Louisiana. https://www.aeaweb.org/conference/2023/program/powerpoint/EYDFa2hz.

30 Pastor, M., Sadd, J., and Hipp, J. 2001. "Which Came First? Toxic Facilities, Minority Move-In, and Environmental Justice." *Journal of Urban Affairs* 23 (1): 1–21. https://doi.org/10.1111/0735-2166.00072.

31 Billias, Christopher. 1998. "Environmental Racism and Hazardous Facility Siting Decisions: Noble Cause or Political Tool?" *Washington and Lee Journal of Civil Rights and Social Justice* 4 (1): 36. https://scholarlycommons.law.wlu.edu/crsj/vol4/iss1/5.

32 Taylor, Dorceta E. 2014. *Toxic Communities: Environmental Racism, Industrial Pollution, and Residential Mobility*. NYU Press. http://www.jstor.org/stable/j.ctt9qglv9.

33 Zhang, Ruohao. "Behind Environmental Injustice: Disparate Siting Industries and Post-siting Demographic Transformation." December 10, 2022. https://www.ruohaozhang.com/uploads/1/3/1/0/131057686/siting_and_migration.pdf.

34 Wolverton, Ann. 2009. "Effects of Socio-Economic and Input-Related Factors on Polluting Plants' Location Decisions." *The B.E. Journal of Economic Analysis & Policy* 9 (1). https://doi.org/10.2202/1935-1682.2083.

35 Banzhaf, S., Ma, L., and Timmins, C. 2019. "Environmental Justice: Establishing Causal Relationships." *Annual Review of Resource Economics* 11 (1): 377–98. https://econpapers.repec.org/article/anrreseco/v_3a11_3ay_3a2019_3ap_3a377-398.htm.

36 Banzhaf, S., Ma, L., and Timmins, C. 2019. "Environmental Justice: The Economics of Race, Place, and Pollution." *Journal of Economic Perspectives* 33 (1): 185–208. https://doi.org/10.1257/jep.33.1.185.

37 Iceland, John. 2019. "Racial and Ethnic Inequality in Poverty and Affluence, 1959–2015." *Population Research and Policy Review* 38 (5). https://doi.org/10.1007/s11113-019-09512-7.

38 Brown, M.A., Soni, A., Doshi, A.D., and King, C. 2020. "The Persistence of High Energy Burdens: A Bibliometric Analysis of Vulnerability, Poverty, and Exclusion in the United States." *Energy Research & Social Science* 70 (December): 101756. https://doi.org/10.1016/j.erss.2020.101756.

39 Baldwin, Davarian L., and Emma S. Crane. 2020. "Cities, Racialized Poverty, and Infrastructures of Possibility." *Antipode* 52 (2): 365–79. https://doi.org/10.1111/anti.12600.

40 Faber, Jacob W. 2020. "We Built This: Consequences of New Deal Era Intervention in America's Racial Geography." *American Sociological Review* 85 (5): 739–75. https://doi.org/10.1177/0003122420948464.

41 Mohai, Paul, and Robin Saha. 2015. "Which Came First, People or Pollution? Assessing the Disparate Siting and Post-Siting Demographic Change Hypotheses of Environmental Injustice." *Environmental Research Letters* 10 (11): 115008. https://doi.org/10.1088/1748-9326/10/11/115008.

42 Pulido, Laura. 2000. "Rethinking Environmental Racism: White Privilege and Urban Development in Southern California." *Annals of the Association of American Geographers* 90 (1): 12–40. https://doi.org/10.1111/0004-5608.00182.

43 Vaz, E., Anthony, A., and McHenry, M. 2017. "The Geography of Environmental Injustice." *Habitat International* 59 (January): 118–25. https://doi.org/10.1016/j.habitatint.2016.12.001.

Indigenous persons, people of color, and low-income communities experience a relatively higher burden of environmental exposure from air, water, and soil pollution from industrialization, militarization, and consumer practices.[44] Being able to distinguish between intent, which requires demonstrated motivation, and impact, which requires a causal relationship, would become a subject of future debates.[45]

B. Federal Action

1. The First Executive Order

On February 11, 1994, President Clinton issued Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations. The purpose was to bring federal attention to the environmental and human health effects of federal actions on minority populations and low-income populations, and the order established an Interagency Working Group on environmental justice.[46]

Sec. 1–101. *To the greatest extent practicable and permitted by law, and consistent with the principles set forth in the report on the National Performance Review, each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations in the United States and its territories and possessions, the District of Columbia, the Commonwealth of Puerto Rico, and the Commonwealth of the Mariana Islands.*

Sec. 2–2. *Each Federal agency shall conduct its programs, policies, and activities that substantially affect human health or the environment, in a manner that ensures that such programs, policies, and activities do not have the effect of excluding persons (including populations) from participation in, denying persons (including populations) the benefits of, or subjecting persons (including populations) to discrimination under, such, programs, policies, and activities, because of their race, color, or national origin.*

It was not until President Clinton's next term that U.S. federal government policy began publishing a singular definition for EJ. The term "environmental justice" was not used in the *Federal Register* in 1990, 1991, or 1992, suggesting that the 1993 publication was the first time this term was used publicly by federal agencies. The term became more popular throughout the late 1990s and into the 2000s.

Nonetheless, to date, there is no landmark federal EJ legislation, and efforts in the movement to seek judicial remedy may have been limited by this. Previous attempts to pass federal law, such as the previously proposed *Environmental Justice Act of 1992*,[47] lacked the votes necessary to pass in Congress. The next attempt at federal EJ was the law introduced in 2018 and again in 2021, entitled the *Environmental Justice for All Act*.[48] While sweeping legislation supporting EJ has faced political challenges, the movement has leveraged other areas of existing law to build jurisprudence to address environmental injustice claims. These include the 14th Amendment to the U.S. Constitution (Equal Protection Clause), the Fair Housing Act of 1968, and the Civil Rights Act of 1964.

2. Making Inroads Through the Civil Rights Act of 1964

Title VI, Sections 601 and 602 of the CRA of 1964,[49] have been the primary mechanism for pursuing remedies for claims related to policies and decisions that have been associated with discriminatory practices and/or led to disproportionate impacts being borne by marginalized, disadvantaged, or otherwise minoritized communities.

44 Mohai, P., Pellow, D., and Roberts, J.T. 2009. "Environmental Justice." *Annual Review of Environment and Resources* 34 (1): 405–30. https://doi.org/10.1146/annurev-environ-082508-094348.

45 Mohai, P., Pellow, D., and Roberts, J.T. 2009. "Environmental Justice." *Annual Review of Environment and Resources* 34 (1): 405–30. https://doi.org/10.1146/annurev-environ-082508-094348.

46 Exec. Order No. 12898, 59 FR 7629 (1994). http://www.archives.gov/federal-register/executive-orders/pdf/12898.pdf.

47 Hasler, Claire. 1994. "The Proposed Environmental Justice Act: 'I Have a (Green) Dream.'" *Seattle University Law Review* 17 (2): 417. https://digitalcommons.law.seattleu.edu/sulr/vol17/iss2/8/.

48 U.S. Congress, U.S. House. "S.2360: Environmental Justice Act of 2021," 117th Congress, 1st Session, introduced in House August 5, 2021. https://www.congress.gov/bill/117th-congress/senate-bill/2630.

49 "Civil Rights Act (1964)." National Archives. https://www.archives.gov/milestone-documents/civil-rights-act#transcript.

Sec. 601*. No person in the United States shall, on the ground of race, color, or national origin, be excluded from participation in, be denied the benefits of, or be subjected to discrimination under any program or activity receiving Federal financial assistance.*

Sec. 602. *Each Federal department and agency which is empowered to extend Federal financial assistance to any program or activity, by way of grant, loan, or contract other than a contract of insurance or guaranty, is authorized and directed to effectuate the provisions of section 601 with respect to such program or activity by issuing rules, regulations, or orders of general applicability which shall be consistent with achievement of the objectives of the statute authorizing the financial assistance in connection with which the action is taken.*

Throughout the 1970s and 80s, Title VI had been EJ advocates' primary tool for litigating perceived injustices. In 2001, the U.S. Supreme Court severely limited this mechanism with a pivotal ruling in *Alexander v. Sandoval.*[50] Previously, EJ advocates would have been theoretically capable of leveraging Title VI (Sections 601 and 602) to claim discrimination via disparate impacts, where the programs that had impacted them had received federal funding as a way to seek EJ remedy. However, Section 601 had less utility for EJ litigants in that discriminatory intent had to be proven, whereas interpretation of 602 allowed for disparate impacts as the determining factor.

In *Alexander v. Sandoval,* the Supreme Court did not decide whether promulgation of Section 602 regulations would prohibit decisions or actions with disparate outcomes and instead focused on what was necessary to bring a private right to action under Section 601. In deciding that Section 601 did not "create a freestanding private right of action to enforce regulations," private litigants were only able to move forward under Section 601 by demonstrating intentional discrimination, which is a high burden of proof. Alternatively, some litigants chose to utilize the 14th Amendment or had to rely on governmental bodies bringing forward claims against other agencies on the private parties' behalf. The enforcement of EJ claims for disparate impact, therefore, was limited by agency capacity to investigate, respond to, and sanction federal funding recipients.[51]

3. Federal Orders

Where legislative votes have been lacking, federal action has been encouraged by EJ advocates through Executive action. Several Executive Orders issued, beginning with the Clinton administration (EO 12898), and continuing into the Biden administration (EO 14008), have tasked individual agencies to develop stewardship and responsibility metrics that hope to address the root cause of environmental injustices and to correct the "disproportionate health, environmental, and economic impacts that have been borne primarily by communities of color," President Biden noted in 2022.[52]

Under the executive orders, each agency has been tasked with developing a jurisdictionally specific mission statement that achieves the outcomes mandated in the orders For the Environmental Protection Agency (EPA), EJ is focused on addressing the environmental vulnerabilities for disadvantaged communities, including quality, access, sustainability, and equitable development. The Department of Energy (DOE) focuses their EJ pursuits on the aspects related to energy justice. Specifically, DOE is developing plans addressing the impact to job security facing energy communities, developing procedures for equitable access to future energy in underserved communities, and safeguarding against disproportionate impact of new energy infrastructure development falling on already impacted

50 "Alexander v. Sandoval." (99-1908) 532 U.S. 275 (2001) 197 F.3d 484, reversed. Supreme Court of the United States. https://www.law.cornell.edu/supct/html/99-1908.ZS.html.

51 Monsma, D. 2006. "Equal Rights, Governance, and the Environment: Integrating Environmental Justice Principles in Corporate Social Responsibility." *Ecology Law Quarterly*, Vol. 33(2); 443-498 https://www.ecolex.org/details/literature/equal-rights-governance-and-the-environment-integrating-environmental-justice-principles-in-corporate-social-responsibility-ana-079574/.

52 Biden, Joe. Earth Day Speech. April 22, 2022. https://www.whitehouse.gov/environmentaljustice/

communities.[53, 54, 55, 56] For the Department of Agriculture, the focus of EJ will be purposefully aimed at improving food supply chains and access to food stocks, building climate resiliency into climate-safe agricultural practices, and improving equity and equality amongst farmers and ranchers.[57, 58, 59, 60] The Department of Justice is focused on improving enforcement and prosecutorial mechanisms for environmental law violations, with a special task force targeting investigations in, or on behalf of, EJ.[61]

C. Evolution from EJ to Energy Justice to Climate Justice to JUSTICE40

The White House Environmental Justice Advisory Council was created by the Biden administration and tasked with providing "recommendations to the White House Environmental Justice Interagency Council established in Section 220 of [Executive Order 14008] on how to increase the federal government's efforts to address current and historic environmental injustice, including recommendations for updating Executive Order 12898."[62] Concurrently, the White House Environmental Justice Interagency Advisory Council was amended, under EO14008, to develop "a strategy to address current and historic environmental injustice by consulting with the White House Environmental Justice Advisory Council and with local environmental justice leaders."[63] EO14008 also mandated that 40% of the overall benefits from certain federal investments flow to disadvantaged communities, under a newly created initiative called Justice40.[64] In addition to moving EJ into mainstream consciousness, the latest governmental actions have expanded justice to include energy justice, climate justice, and

THE MEANING OF ENVIRONMENTAL JUSTICE

With growing awareness of environmental injustices and the mainstream consciousness to the EJ movement, the term "environmental justice" has come to mean many different things to different people. EJ is primarily and historically a movement for equitable treatment led by Black grassroots leaders. The term EJ is also used to describe specific communities that may have faced disproportionate and cumulative negative environmental impacts and burdens. EJ has also been adopted as an academic term and a policy framework. "Apart from how competing notions of environmental justice shape ongoing interpretations of social justice or civil rights, 'the quest for environmental justice' presumably does not end with 'an equitable distribution of negative externalities.'"[a]

a. Heiman, Michael K. 1996. "Race, Waste, and Class: New Perspectives on Environmental Justice." Antipode 28 (2): 111–21. https://doi.org/10.1111/j.1467-8330.1996.tb00517.x.

53 DOE. "Creating Clean Energy Union Jobs." https://www.energy.gov/creating-clean-energy-union-jobs.

54 DOE. "Promoting Energy Justice." https://www.energy.gov/promoting-energy-justice.

55 DOE. "About Community Benefits Plans." https://www.energy.gov/infrastructure/about-community-benefits-plans.

56 DOE. "Fossil Energy and Carbon Management Domestic Engagement Framework: Engaging Communities, Stakeholders, and Tribes in Clean Energy Technologies." https://www.energy.gov/fecm/fossil-energy-and-carbon-management-domestic-engagement-framework-engaging-communities.

57 USDA. "Equity at USDA." https://www.usda.gov/equity.

58 USDA. "Climate Solutions." https://www.usda.gov/climate-solutions.

59 USDA. "Equitable Systems." https://www.usda.gov/nutrition-security/equitable-systems.

60 USDA. "Environmental Justice." 1997. https://www.usda.gov/directives/dr-5600-002.

61 "Memorandum for Heads of Department Components United States Attorneys From: The Associate Attorney General Subject: Comprehensive Environmental Justice Enforcement Strategy." 2022. https://www.justice.gov/d9/pages/attachments/2022/05/05/02._asg_strategy_memorandum.pdf.

62 The White House. "Executive Order on Tackling the Climate Crisis at Home and Abroad". Sec 221.d. January 27, 2021. https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/27/executive-order-on-tackling-the-climate-crisis-at-home-and-abroad/.

63 The White House. "Executive Order on Tackling the Climate Crisis at Home and Abroad." 219.d. January 27, 2021. https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/27/executive-order-on-tackling-the-climate-crisis-at-home-and-abroad/.

64 The White House. "Executive Order on Tackling the Climate Crisis at Home and Abroad." Sec 233. January 27, 2021. https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/27/executive-order-on-tackling-the-climate-crisis-at-home-and-abroad/.

intersectional movements that have joined with EJ over the past several decades.

There is currently no national database for tracking state- and municipal-level EJ legislation—something sorely lacking from the public sector considering the focus on local decision-making. As of 2022, 14 states have developed or are currently developing EJ legislation.[65, 66] However, there is significant diversity in the aims of these laws.[67] Some call for EJ impact assessments, while others focus on enhancing stakeholder engagement in decision-making.[68] Several states have mandated—and developed—state-specific screening tools to help capture unique dynamics at a local level that national tools (i.e., EJScreen or Climate and Economic Justice Screening Tool) do not capture. The latest trend has been focused on permitting reforms and utilizing cumulative impact assessments to address potential risks related to disproportionate siting or expansions of future projects in self-described overburdened communities.[69] There is risk that unharmonized legislation could create contradictions between state and federal efforts.[70] For example, how a state defines EJ populations could be different from national definitions of disadvantaged communities.[71, 72] If designed in a complementary manner, state-based EJ efforts can provide missing localized information, legislation, regulation, and enforcement that strengthens EJ considerations in the absence of federal authority or action. As former EPA administrator Bill Reilly stated: "Any effort to address environmental equity [justice] issues effectively must include all segments of society: the affected communities, the public at large, industry, people in policy-making positions, and all levels and branches of government."[73]

Beyond pursuing governmental intervention, EJ organizers remain focused on grassroots mobilization in the movement-policy cycle.[74] The movements, while focused on addressing localized issues, have sought international tactical collaboration to build support. With broader movements such as energy justice, climate justice, and second-generation EJ advocacy, new groups and movements have found intersections with each other. Those connections have led to the development of

65 Griffin, Nicholas. 2022. "Scorecard of Environmental Justice Policies in Northeast-Midwest States." Northeast-Midwest Institute. July 2022. https://www.nemw.org/wp-content/uploads/2022/08/Environmental-Justice-Report-and-Scorecard-August-5-2022.pdf.

66 Bruce, Dylan. 2021. "Analysis: State Laws Are Codifying Environmental Justice." *Bloomberg Law*. https://news.bloomberglaw.com/bloomberg-law-analysis/analysis-state-laws-are-codifying-environmental-justice.

67 "Emerging State-Level Environmental Justice Laws." *New York Law Journal*. May 12, 2021. https://www.law.com/newyorklawjournal/2021/05/12/emerging-state-level-environmental-justice-laws/.

68 Torres-Sota, Elissa. "2022 in Review: State Environmental Justice Laws and Policies". Environmental Law Institute. January 9, 2023. https://www.eli.org/vibrant-environment-blog/2022-review-state-environmental-justice-laws-and-policies#:~:text=To%20date%2C%20there%20are%2014.

69 "New York State Senate Bill S8830." 2022. New York State Senate. https://www.nysenate.gov/legislation/bills/2021/S8830.

70 Perls, Hannah. 2020. "EPA Undermines Its Own Environmental Justice Programs-Environmental & Energy Law Program." Harvard Law School. November 12, 2020. https://eelp.law.harvard.edu/2020/11/epa-undermines-its-own-environmental-justice-programs/.

71 Majumder, Myisha. "Environmental Justice Is a Growing Operational Factor. How Are Federal and State Agencies Defining It?" February 22, 2023. *Waste Dive*. https://www.wastedive.com/news/environmental-justice-definition-epa-disadvantage-community/642809/.

72 Fernandez-Bou, A.S., Ortiz-Partida, J.P., Dobbin, K.B., Flores-Landeros, H., Bernacchi, L.A., and Medellín-Azuara, J. 2021. "Underrepresented, Understudied, Underserved: Gaps and Opportunities for Advancing Justice in Disadvantaged Communities." *Environmental Science & Policy* 122 (August): 92–100. https://doi.org/10.1016/j.envsci.2021.04.014.

73 Letter from EPA Environmental Equity Workgroup to EPA Administrator, which covers the EPA Environmental Equity report: "Reducing Risks for All Communities." June 1992.

74 Kane, Melinda. 2003. "Social Movement Policy Success: Decriminalizing State Sodomy Laws, 1969–1998." *Mobilization: An International Quarterly* 8 (3): 313–34. https://doi.org/10.17813/maiq.8.3.q66046w34wu58866.

coalitions,[75] alliances, and global awareness of EJ issues.[76, 77, 78]

While EJ has been a uniquely focused, activist-led effort in the United States, it is important to note that these concerns are not only a domestic issue, with a broader, international dialogue having developed simultaneously. However, unlike the United States, many countries have less well-developed environmental and civil rights protection frameworks to leverage. Internationally, this lack of institutionalized environmental and civil rights protection frameworks and policies has engendered a more grassroots-based, cross-movement strategy. In 2001, EJ leaders piloted a grassroots approach by consciously working with environmentalists and conservation organizers focused on Amazonian concerns, with social justice advocates representing urban concerns.[79] These Amazonian mobilization efforts resulted in intersections with issues, policies, or sensitivities from different ideological and historical contexts. This approach is referred to as "intersectionality" and is increasingly an important organizing methodology for EJ. Just as early organizers, such as Cesar Chavez[80] and Martin Luther King, Jr.,[81] worked to create intersectional coalitions between environmental and civil concerns and labor movements, organizers today are seeking to build coalitions and multifront campaigns that address EJ, labor, civil rights, climate justice, sovereignty concerns, and many others at the same time.[82]

Some EJ advocates have been involved since the inception of the movement with mobilized protestations, such as the aforementioned Warren County PCB landfill siting decision. These organizers view EJ as an intersection of civil rights, labor rights, and the need for stronger environmental protections for overburdened communities.[83] Consequently, their organizations are deeply rooted in addressing systemic issues, building equity, and centering community decision-making.[84] Other organizers are being shaped by a broader environmentalism perspective that arose after the 1970s. These organizers push racial, social, and climate justice as a globally unifying platform.[85] The new-wave EJ movement still leverages protest tactics,[86] but has moved to a more global focus; these organizations describe their missions as trying to address climate vulnerabilities, democratic participation, community sovereignty, and equitable adaptation,[87] and are broadly against future pollution and industrialization.[88]

For local organizers, mobilizing is focused on directing activity to address procedural issues related to public participation, holding

75 Pellow, David N. "Transnational Alliances and Global Politics: New Geographies of Urban" in *In the Nature of Cities*, 1st ed. 2005. https://www.taylorfrancis.com/chapters/edit/10.4324/9780203027523-21/transnational-alliances-global-politics-new-geographies-urban-environmental-justice-struggles-david-pellow.

76 Pellow, David N. 2005. *In the Nature of Cities Urban Political Ecology and the Politics of Urban Metabolism*. Routledge.

77 Martínez-Alier, Joan. 2012. "Environmental Justice and Economic Degrowth: An Alliance between Two Movements." *Capitalism Nature Socialism* 23 (1): 51–73. https://doi.org/10.1080/10455752.2011.648839.

78 Walker, Gordon. 2009. "Globalizing Environmental Justice." *Global Social Policy* 9 (3): 355–82. https://doi.org/10.1177/1468018109343640.

79 Porto, Marcelo Firpo. 2012. "Movements and the Network of Environmental Justice in Brazil." *Environmental Justice* 5 (2): 100–104. https://doi.org/10.1089/env.2011.0012.

80 Chavez, Cesar. 1986. "Four Freedoms Curriculum Resource." https://learn.nrm.org/media/1242/cesar-chavez-wrath-of-grapes-speech.pdf.

81 "'I've Been to the Mountaintop' by Dr. Martin Luther King, Jr. American Federation of State, County and Municipal Employees (AFSCME)." April 3, 1968. https://www.afscme.org/about/history/mlk/mountaintop.

82 Thomas, Leah. *The Intersectional Environmentalist*. The Hachette Book Group. 2021. https://www.hachettebookgroup.com/titles/leah-thomas/the-intersectional-environmentalist/9780316281935/?lens=voracious.

83 Obach, Brian K. 2004. *Labor and the Environmental Movement*. The MIT Press. https://doi.org/10.7551/mitpress/4080.001.0001.

84 Wilgosh, B., Sorman, A.H., and Barcena, I. 2022. "When Two Movements Collide: Learning from Labour and Environmental Struggles for Future Just Transitions." *Futures* 137 (March): 102903. https://doi.org/10.1016/j.futures.2022.102903.

85 As an example, see: "A Movement for Racial Justice." Rainforest Action Network. https://www.ran.org/issue/a-movement-for-racial-justice/.

86 Baptista, A.I., Jesudason, S., Greenberg, M., and Perovich, A. 2022. "Landscape Assessment of the U.S. Environmental Justice Movement: Transformative Strategies for Climate Justice." *Environmental Justice* 16 (2). https://doi.org/10.1089/env.2021.0075.

87 Schlosberg, David, and Lisette B. Collins. 2014. "From Environmental to Climate Justice: Climate Change and the Discourse of Environmental Justice." *Wiley Interdisciplinary Reviews: Climate Change* 5 (3): 359–74. https://doi.org/10.1002/wcc.275.

88 Dawson, Ashley. 2010. "Climate Justice: The Emerging Movement against Green Capitalism." *South Atlantic Quarterly* 109 (2): 313–38. https://doi.org/10.1215/00382876-2009-036.

governmental agencies accountable to rules and environmental laws related to pollution or exposure to hazardous products, and, wherever possible, opposing new industrial facilities being sited in their communities. For international players, organizations may focus on nation-state intervention.[89] In doing so they may seek to highlight lack of state action in addressing displacement of harm on hemispheric divides,[90] exportation of hazardous products,[91] exploitation of sovereign resources,[92] and lack of adherence to EJ programs.[93] Organizations may also focus on publicity via "name and shame"[94, 95] campaigns or other documentarian methods.

In the future, the EJ lexicon may become more prescriptive and the definitions around EJ, energy justice, and climate justice may be normalized to ensure clarity in both the usage and application of these principles and frameworks across local, regional, national, and transnational environments. Environment, social, and governance (ESG) information reporting provides one such framework that could be leveraged to encourage voluntary adoption of, and adherence to, normative EJ principles through public commitments that are linked to community engagements and stakeholder responsibilities. As stated by Showalter and Antoniolli (2023), "EJ falls at the intersection of the "E" and "S" of ESG and good

CASE STUDY OF THE TRADE-OFFS COMMUNITIES EXPERIENCE SPECIFIC TO NATURAL GAS DEVELOPMENT ACTIVITIES

A study of the social consequences in the Marcellus Appalachia region documented community responses of positive and negative impacts of natural gas development activities. Economic benefits were the number one positive benefit according to communities. These benefits were not limited to monetary value, but included elements like training opportunities for youth to remain in the local region, thereby creating generational family stability and enhanced financial stability for the elderly, etc. The indirect benefits included themes like long-term business development for alternative sectors, like agriculture—which allowed the community to retain its identity. These factors contributed to improved indicators of enhanced quality of life.[b]

The negative consequences reported in the study were concentrated around the "ramp-up" stages of development when drilling activities commenced. This included traffic congestion, dirt, noise, damage to existing infrastructure, population increases with "newcomers," increase in crime rates, lack of housing and utility infrastructure, and a lack of trained workers to support the development activities. Some of the negative impacts extended to the operational or post-production stages of activities, including unfair/unequal treatment of homeowners by energy companies (i.e., signing bad leases), minimal royalties, and negative environmental impacts.

b. Gorman, Mary. "Social Consequence, Stakeholder Influence, and Resource Needs for Marcellus Shale Communities." ScholarWorks. December 2014. https://scholarworks.waldenu.edu/cgi/viewcontent.cgi?article=1102&context=dissertations.

89 Koliev, F., Park, B., and Duit, A. 2022. "Climate Shaming: Explaining Environmental NGOs Targeting Practices." *Climate Policy* 23 (7): 1–14. https://doi.org/10.1080/14693062.2022.2143315.

90 United Nations. "Plastic Pollution Disproportionately Hitting Marginalized Groups, UN Environment Report Finds." *UN News*. March 30, 2021. https://news.un.org/en/story/2021/03/1088712.

91 Wang, K., Qian, J., and He, S. 2021. "Contested Worldings of E-Waste Environmental Justice: Nonhuman Agency and E-Waste Scalvaging in Guiyu, China." *Annals of the American Association of Geographers*, 11 (7): 1–20. https://doi.org/10.1080/24694452.2021.1889353.

92 Valencia, Robert. "She Grew up in the Amazon, and Now She's Fighting for Its Life." *Earthjustice*. January 6, 2023. https://earthjustice.org/article/she-grew-up-in-the-amazon-and-now-shes-fighting-for-its-life.

93 Perls, Hannah. "EPA Undermines Its Own Environmental Justice Programs-Environmental & Energy Law Program." Harvard Law School. November 12, 2020. https://eelp.law.harvard.edu/2020/11/epa-undermines-its-own-environmental-justice-programs/.

94 Barnes, Ash, and Rob White. 2020. "Mapping Emotions: Exploring the Impact of the Aussie Farms Map." *Journal of Contemporary Criminal Justice*, 36 (3). https://doi.org/10.1177/1043986220910306.

95 "'We Don't Have Any Choice': The Young Climate Activists Naming and Shaming U.S. Politicians." *The Guardian*. October 16, 2020. https://www.theguardian.com/environment/2020/oct/16/sunrise-movement-wide-awakes-us-climate-activists.

Governance is required to manage exposure to EJ risks."[96]

Many corporate risks are managed through good risk management practices that are made available to the public and investors. Investors often leverage nonfinancial, nonregulated ESG ratings as a differentiating factor for their investment decisions; several companies have taken the step to "incorporate equity and EJ [principles] holistically into their operations and across their supply chains, in furtherance of corporate social responsibility goals and as strategies for market differentiation."[97] The lack of industry disclosure of EJ does not mean there is a lack of awareness or consideration of these tenets. In fact, EJ principles and tenets are incorporated into some companies' broader commitments or approaches to managing environmental and socioeconomic impacts, as well as through formal economic development programs. In some cases, these programs are specifically designed to be supportive of local communities particularly vulnerable to industry activity. Just as community best practices encourage highly participatory local engagement processes, incorporating EJ principles into ESG as an explicit disclosure depends upon dialogue and collaboration, and on the position investors and corporate operators take toward addressing and upholding EJ tenets and principles.

II. IMPLEMENTING COMMUNITY ENGAGEMENT BEST PRACTICES

The joint Charting the Course *and* Harnessing Hydrogen *study task group analyzed several community and stakeholder engagement best practices and guidance reference documents, referenced throughout Chapter 2 and in this appendix. The analysis resulted in the identification and elevation of the following characteristics and formed the basis of the community engagement model that both studies developed. The* Charting the Course *study went on to test the engagement model through focus groups and an associated poll.*

A. Implementation of Best Practices

The following guidance is for the implementation of best practices for all stakeholders—federal and state agencies, local governments, Tribal governments, private citizens, and public interest groups, and industry—to strive for better community engagement, as well as to meet and accomplish the regulatory objective more effectively.

1. The Four-Step Framework

Step 1: Prepare

Project developers should begin by identifying potential impacts, both beneficial and adverse, and all potentially impacted communities. Developers should also identify stakeholders to understand their history, culture, land use, socioeconomic activities, political organization, relationships with prior developers, past economic development efforts, and the community members and neighborhoods that will be most affected by the project. Doing so is part of an authentic intent to deepen understanding and build trust.

It is also important to develop a deep understanding of the community's values—what matters to them and how the project might advance local interests. This should be studied well before community engagement and refined as the project developers engage with community. In addition, to cultivate a collaborative process of engaging with communities, project developers should aim to obtain early endorsement of the *processes* rather than the project itself.[98] Project developers should be ready to discuss potential impacts, both positive and negative.

Integration of Indigenous and/or local knowledge, through literature review and subsequent field research, should be undertaken. This may include broad categories such as local livelihoods and culture, sociodemographic and socioeconomic data, traditional resources, ecosystem services, culturally sensitive environments, and potential

96 Showalter, Michael J., and Amy Antoniolli. "What Do ESG and Environmental Justice Actually Mean?" *National Law Review*. February 23, 2013. https://www.natlawreview.com/article/esg-and-environmental-justice.

97 Halliday, S., Redd, J., and Glickstein, J. "Addressing Environmental Justice as Part of ESG Initiatives," *Law360*. May 24, 2021. https://www.law360.com/articles/1384123/addressing-environmental-justice-as-part-of-esg-initiatives.

98 Chavez, Marques. "Vermillion Wind Energy Project." Keystone Policy Center. February 2023. https://www.keystone.org/vermillion-wind-energy-project/.

social project needs. The list is nonexhaustive and should be informed by local circumstances and needs. Recommended Reading: *UN Declaration on the Rights of Indigenous Peoples* (2007).[99]

In undertaking preparation and community impact assessments, the initial screening (desktop research) can make use of tools available at the federal and some state government levels. It is important to note there is not a single tool, but various agencies have them available, including EPA, DOE, and the White House Council on Environmental Quality Climate and Economic Justice Screening Tool.[100] None of these tools replace the full preparation work described above, but they can help identify existing or potential EJ considerations for communities and associated risks/needs. Refer to Section I of this appendix on the history of EJ for additional information.

Step 2: Listen

To establish and improve the value of a proposed project, communities affected by a project must have opportunities to communicate with developers. While many meetings begin with sharing early plans or intentions, active listening is a continuous practice that starts with observing as much as possible.

Positive community engagement also involves acknowledging the role of communities and their voices, being open to active listening, and developing a good understanding of community members developed during the preparation step.

Step 3: Understand and Respond

For developers to understand and respond authentically, it may be necessary to identify methodologies for selecting the right messenger(s). Bringing colleagues with diverse perspectives and experiences can encourage community members to engage more openly and help equip developers to better understand what is being said or interpreted.

Ensure that leaders are chosen by their respective communities to make certain the process maintains representation and accountability.

Gathering notes, reflecting upon the full range of feedback, and asking clarifying questions are important steps. Having follow-up conversations and sharing back to the community what you've heard are equally important parts of this process.

Wherever communities have expressed needs that are within a developer's purview and capability to address, developers could strive for finding mutually beneficial solutions. Where community interests are difficult to accommodate, the developer may take care to convey the reasons for the lack of accommodation, including cases where the industry may not be able to adequately address community concerns or needs.

Be ready to have a community build upon (or reject) the understanding that is shared back to them and continue pursuing mutually recognized understanding. As conversations progress, redouble efforts in active listening.

Step 4: Learn

Commit to continued learning and reflection on the stakeholder engagement practices. As conversations progress, expect that engagement plans will need to evolve and improve as those proposing the action and the community learn how best to work together and the needs of the community come into better focus.

Identifying and responding to community input (as is discussed below as a principle) is recognized to be an important part of learning, requiring project team flexibility.

Note that beyond best practice community engagement, flexibility is also important to addressing justice concerns. Agility, or the ability to shift gears and adjust plans as needed to meet the needs of the community, is invaluable. In fact, it is impossible to predict at the outset of a project, or at the project application stage, what a complete stakeholder engagement strategy will be. Stakeholder engagement plans need to allow for flexibility and should be allowed to change over time to accommodate the dynamic nature of stakeholder engagement. For example, concerns

99 United Nations. 2007. "United Nations Declaration on the Rights of Indigenous Peoples." https://www.un.org/development/desa/indigenouspeoples/wp-content/uploads/sites/19/2018/11/UNDRIP_E_web.pdf.

100 "Climate and Economic Justice Screening Tool." *U.S. Climate Resilience Toolkit*. 2023. https://toolkit.climate.gov/tool/climate-and-economic-justice-screening-tool.

in the activation phase of hydrogen development will be very different than concerns and needs in the at-scale phase; a static engagement would be insufficient to address the myriad concerns across that period.

2. The Iterative Aspect

Although the four steps (prepare, listen, understand/respond, learn) imply iterative or even continual improvement processes, this aspect is itself a required element of best practice community engagement. An ongoing venue for addressing grievances, as well as opportunities, should be present during project design, permitting, construction, and operation. This will look different for every project, depending on the scale, size, and type of project being proposed. Some options include community advisory boards, town halls, reporting web portals, or hotlines. The same due diligence will be required for these programs to ensure accessibility and support effective community use. Listening and/or understanding without response and learning would not align to the principles that accompany this framework. On the other hand, responding well helps bring alignment to these principles.

3. The Five Principles of the 4-Step Framework

Principle 1: Bringing Authenticity; Building Trust and Goodwill

Communities that have suffered discrimination or are disadvantaged seek recognition of historical injustices and will look for this as part of building deep trust. Industry proposals that seek to reduce inequities may garner more support and foster more trust. Stakeholders should be supported as needed and have access to the same opportunities that industrial activities may bring to a community. Beyond technical knowledge, behaviors that are authentic, respectful, and nonextractive reduce mistrust, particularly from communities that have been exposed to industrial impacts. Demonstrating plans to create and utilize better processes is an early trust-building step in engagement. For example, meaningful dialogue may lead to identifying areas of mutual interest, such as minimally invasive development practices that preserve and protect sacred sites and sensitive ecosystems or improving supplier diversity and local worker participation through training and other workforce development practices.

Note that the "Prepare" element of the 4-Step Framework is important not only for effective listening, but specifically for building trust and bringing authenticity. In addition, an effective community engagement process will vary because no two projects or communities are alike, and solutions that address EJ will not look the same for each project given these differences. Working to address EJ requires meaningful community engagement, especially with collaboration among project partners, impacted community members and organizations, businesses, multiple levels of government, and sometimes other third-party resource partners (e.g., facilitators).

Meeting the community where they are, in places where they commune regularly, will help identify leaders and representatives. These different stakeholders will each have roles to play in advancing meaningful community engagement. Industry engagement that seeks to address EJ goals can build authenticity, goodwill, and trust within the community. Where possible, working in partnership with local organizations that have relationships with the community, including a diverse range of leaders, will help to define a stakeholder engagement strategy well suited to the local context.

Local organizations can help with identifying representative voices of the community, navigating local politics, advising on message development, and serving as a bridge to the people. Project developers should make sure that representatives of the community are respected and that those who will be directly affected by a project are treated fairly and have meaningful involvement in decision-making, planning, and plan execution. Industry should work with community groups and members to co-define the vision and scope of a community-driven engagement process. Establishing a long-standing, trusted relationship in a community takes time, commitment, and perseverance, and developing strong relationships with local organizations can be an important first step. During this process, to signal true cooperation

with community, project developers may benefit from early engagement after optioning the site, but before land easement acquisition and project site-map finalization. Engaging communities via political leadership and public relations pathways that lack a listening element may not build trust or good will.

Principle 2: Transparency

All parties involved in community engagement should be transparent about the interests they are representing. Different individuals will define transparency in different ways. For this reason, transparency guidelines should be defined with the community.

When approaching a meaningful process, industry should be transparent about the intentions, commitments, objectives, and anticipated outcome of the engagement, with the recognition that there are specific forms of information that are confidential for specific reasons. For example, certain details about infrastructure are not disclosed because they would increase infrastructure vulnerability from a safety or security perspective. Transparent disclosure by industry should include a discussion about the potential risks and limitations associated with the proposed project.

Industry should use community-informed planning and implementation processes to solicit engagement that involves openly communicating desired outcomes and soliciting community input early and at defined points throughout the project implementation. Industry should communicate its intentions clearly and ensure the community understands the purpose of the proposed action and opportunities for their voices to be heard. The community should be made aware of the proposed schedule for implementation, what they can expect during each phase of the action, and plans for accountability to the community members once the action is complete. To do so, industry should consider documented engagement plans that are regularly updated with outcomes and checkpoints in a phased approach. Documentation allows for clear communication and the opportunity to refer to commitments and agreements, and/or changes. Keeping communities engaged throughout all levels of planning and implementation is key to demonstrating that they too, have an instrumental role in the process and outcome and are treated as respected partners and their local expertise is valued.

Principle 3: Early, Open, Responsive, and Accessible Engagement

Engaging early and often with the impacted and surrounding communities is key to building relationships. Providing consistent, transparent, and easy-to-understand project information while soliciting feedback are equally critical, as is both the communication of benefits and the determination of whether a community recognizes those benefits.

To do this, the mechanism and accessibility, as well as the inclusivity of stakeholder voices, will be fundamental to successful engagement. Ensure there are effective and sufficient means to reach the community by considering potential communication or participation barriers, including language, technology, transportation, and temporal barriers (childcare or competing priorities), etc.

In the United States, regulatory public comment processes have a formal structure and tend to occur after project design is well underway. As mentioned above, these processes cannot be taken as sufficient engagement. Their formal nature—which often includes written comments submitted via government websites or public hearings where participants must request to speak and stand at a microphone—can be an obstacle to maximizing community participation. Developers should be mindful of the formality barrier when they consider the input gathered in these processes.

Best practice community engagement should place particular emphasis on facilitating participation by underrepresented communities. For example, developers should plan on providing educational and informational resources, including their direct community engagement processes, according to local needs. This may mean providing multilingual resources and materials to facilitate engagement with non-English speakers, or adaptive accommodations for disabled

individuals such as live American Sign Language translation for in-person events or TeleTypewriter (TTY) and/or TTY Relay Services for telephone engagements. Fortunately, there are many national and local community-based organizations serving these diverse groups that can provide guidance on specific accommodation-based best practices.

Incorporate plans that address skepticism, especially communities that have been harmed by similar actions previously or see little value in the action for them. This additional effort might take the form of meeting communities where they are, rather than expecting them to go to an event, or reaching out over time with information to help build a relationship of trust.

In engaging communities throughout the life of the project, it is also important for project leads to examine, understand, and honestly articulate answers to the following questions:

- Who is participating? Who is missing from the discussion and why?
- What are the primary modes and methods of communication and decision-making being utilized here? How well do these methods fit the purpose?
- How much influence do participants have in the decision-making or actions taken? How well do participants understand their influence or responsibility?

Successful engagement and communication also ensure that all voices are heard and included in project input, including a variety of community leaders as well as disenfranchised communities and community members. Strive toward a diversity of viewpoints and experiences that provide a full sweep of those impacted by the project, as not all opinions are represented in community leadership or government.

Likewise, industry needs to be timely and responsive to requests, input, grievances, and feedback. It may take time for community members to be comfortable providing input and it may take various formal and informal methods (individual side conversations, emails, letters, etc.) to achieve true engagement.

Principle 4: Identifying and Responding to Community Input and Concerns

Creating a mechanism to track community feedback and needs is important to ensure actions are aligned with community requests, issues, and grievances. This is critical for establishing credibility and is a core area of the United Nations Guiding Principles. The International Petroleum Industry Environmental Conservation Association (IPIECA) has a detailed document covering this important work.[101] Having a community feedback tracking mechanism is crucial for identifying trends, ensuring resources are addressing the appropriate issue area, and adjusting engagement and response strategies as needed. A Plan-Do-Check-Act (PDCA) management system can be used to measure this. The PDCA includes creating strategies and plans, executing them, checking actions for conformity, and using results to adjust the next generation of plans. Learning from experiences and continuous improvement using PDCA are essential to measure and convey how feedback and actions are being considered and addressed properly.

Principle 5: Articulation of Community Value (by Developer) and Recognition of Value (by the Community and Government)

Community engagement is crucial for ensuring trust, credibility, and effectiveness in the engagement process. All involved are accountable for the outcomes of the engagement process. This includes following through on commitments made, providing updates on progress, and ensuring that the process leads to tangible results and improvements.

Each community has unique social and economic needs based on a variety of factors, including demographics, geographical landscape and ecosystems, civic and political views, and media use. Understanding community members, identifying what they value, and prioritizing historical, current, and future needs of a community and/or region is critical.

101 "Community Grievance Mechanisms in the Oil and Gas Industry." IPIECA. May 1, 2014. https://www.ipieca.org/resources/community-grievance-mechanisms-in-the-oil-and-gas-industry.

At the community and stakeholder level, there may be various concerns across the natural gas supply chain. The magnitude and nature of local concerns and potential impacts or benefits vary by project type, size, technology, and regional context, requiring that community impact and perceptions be assessed on a project-by-project basis. As community needs are identified through the input and feedback from community members, resources—including community investments and volunteerism—and responses can be aligned. The inset "Example Scenario of Balancing Multiple Community Perspectives and Differing Concerns for a Single-Project Element" provides a scenario and potential response to a given community's concern.

III. SELECT DEFINITIONS

There are several concepts and definitions that are important to public dialogue around social equity and EJ and are relevant for the evolving way that industries engage with communities. These definitions are fundamental to understanding communities and accounting for EJ considerations. Organizations, industry, and policymakers all should seek to understand the concept of tenets of justice.

Actions to address the five tenets—restorative justice, recognition justice, procedural justice, distributional justice, and cosmopolitan justice—are considered by many as the pathway to promoting environmental, climate, or energy justice.

The definitions in the next section help clarify this model and implicitly involve best practice community engagement with emphasis on disadvantaged communities.

It is important to recognize that there are different definitions of EJ, differing concerns, and differing ideas of what should be done to address EJ concerns. In evaluating environmental injustices, it is important to account for not just contemporary socioeconomic characteristics, historical contexts, and conditions that communities perceived as creating disparate burdens for them. EJ, then, must center lived experiences of the communities experiencing the inequities and injustices and, secondly, must work with those communities to identify pathways to remedy and create equity within those communities.

A. Definitions & References

Procedural justice seeks to achieve fairness in decision-making processes. It involves identification of who makes plans and decisions (e.g., in an energy development project), who can have a say in the planning and decision-making process, what modes of decision-making are leveraged, and the extent or ability to which those involved can influence or contribute to the decision-making. Therefore, procedural justice is concerned with accessibility, meaningful participation, transparency, fair representation, and diversity of perspectives in the decision-making process.[102]

Distributional justice deals with the equitable allocation of burdens and benefits. It involves the identification of the specific benefits and costs associated with energy development, solutions or decisions, identification of entities, stakeholders, or groups to whom benefits and burdens are to be shared among, and fairness in the basis and modes of distribution of the identified burdens and benefits.[103]

Recognition justice requires that historical inequities and context of disproportionate vulnerability be addressed in planning solutions. Recognition justice centers vulnerable groups (e.g., underemployed populations, communities facing high poverty and health risks, groups facing participation challenges) and requires that processes, decisions, or solutions do not result in worsened outcomes or further harms for those vulnerable groups.[104]

102 Sovacool, B.K., Martiskainen, M., Hook, A., and Baker, L. 2019. "Decarbonization and Its Discontents: A Critical Energy Justice Perspective on Four Low-Carbon Transitions." *Climatic Change* 155 (4): 581–619. https://doi.org/10.1007/s10584-019-02521-7.

103 Romero-Lankao, Patricia, and Erin Nobler. "Energy Justice: Key Concepts and Metrics Relevant to EERE Transportation Projects." NREL. June 2021. https://www.nrel.gov/docs/fy21osti/80206.pdf.

104 Romero-Lankao, Patricia, and Erin Nobler. "Energy Justice: Key Concepts and Metrics Relevant to EERE Transportation Projects." NREL. June 2021. https://www.nrel.gov/docs/fy21osti/80206.pdf.

Cosmopolitan justice refers to justice concerned with the wellbeing of all human beings as members of a global community. It drives the notion that the fair treatment of all individuals is the key to producing communal benefit that goes beyond specific stakeholders, communities, and nations. In energy solutions, cosmopolitan justice requires assessment of benefits and impacts that considers a global community.[105]

Restorative justice combines concepts of procedural, distributional, recognition, and cosmopolitan justice to codevelop plans and solutions that redress existing injustices and prevent future injustices. It therefore leverages collaboration, trust, and restoration of social relationships as a framework for repairing and preventing environmental and social harm caused by past, existing, and future energy systems.[106]

Energy justice is centered on achieving access to energy that is affordable, safe, and able to sustainably support decent life for all individuals. It is a branch of EJ with a specific focus on energy systems and resources. Energy justice combines distributional, recognition, and procedural justice for equitable social and economic participation of all individuals in the energy system.[107]

Climate justice, also related to EJ and energy justice, is focused on justice as it pertains to the costs and benefits of climate action and inaction. It is concerned with recognition, distributional, procedural, and cosmopolitan justice in addressing the disproportionate impacts of climate change and the uneven costs and benefits associated with climate mitigation and adaptation policies and actions (those taken and not taken).[108]

Energy Community: The Inflation Reduction Act (IRA) defines energy communities as a community that has been historically sited near environmentally harmful industries, like coal mining or oil extraction. It also refers to a community where a certain percentage of their tax base is reliant on fossil fuel industries. Critically, IRA offers a specific legal definition of an energy community for the tax credit bonus, defining it as one of three different geographical categories:

1. **A brownfield site:** a term that describes a disused or abandoned land that is polluted from industrial activity. The IRA borrows the definition of a brownfield site from certain subparagraphs of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980.

2. **A metropolitan statistical area or nonmetropolitan statistical area** that has disproportionately relied on the fossil fuel economy, specifically defined as:

   a. "Has (or, at any time during the period beginning after December 31, 2009, had) 0.17% or greater direct employment or 25% or greater local tax revenues related to the extraction, transport, or storage of coal, oil, or natural gas AND

   b. Has an unemployment rate at or above the national average unemployment rate for the previous year."

3. **A census tract (or directly adjoining census tract):**

   a. In which a coal mine closed after December 31, 1999

   b. In which a coal-fired electric generating unit has been retired after 2009

The DOE has put together a helpful mapping tool to show which areas qualify as energy communities under the IRA.[109]

105 Romero-Lankao, Patricia, and Erin Nobler. "Energy Justice: Key Concepts and Metrics Relevant to EERE Transportation Projects." NREL. June 2021. https://www.nrel.gov/docs/fy21osti/80206.pdf.

106 Romero-Lankao, Patricia, and Erin Nobler. "Energy Justice: Key Concepts and Metrics Relevant to EERE Transportation Projects." NREL. June 2021. https://www.nrel.gov/docs/fy21osti/80206.pdf.

107 Carley, Sanya, and David M. Konisky. 2020. "The Justice and Equity Implications of the Clean Energy Transition." *Nature Energy* 5 (8): 569–77. https://doi.org/10.1038/s41560-020-0641-6.

108 Dolšak, Nives, and Aseem Prakash. 2021. "Three Faces of Climate Justice." *Annual Review of Political Science* 25 (1). https://doi.org/10.1146/annurev-polisci-051120-125514.

109 Internal Revenue Service. "Energy Community Bonus Credit Amounts under the Inflation Reduction Act of 2022." 2023. https://www.irs.gov/credits-deductions/frequently-asked-questions-for-energy-communities. https://www.irs.gov/pub/irs-drop/n-23-29.pdf.

IV. FOCUS GROUP REPORT – OCTOBER 10, 2023

IN-PERSON FOCUS GROUPS METHODOLOGY STATEMENT

Focus groups allow for an in-depth, qualitative exploration of the dynamics underlying the public's attitudes toward complex issues. Insights from participants in these focus groups were important to the survey design, and actual quotes were drawn from the focus groups to give voice to attitudes captured statistically through the surveys. All focus groups were moderated by Hudson Pacific principals. One focus group was conducted with general-public members of each of the following communities associated with natural gas production, distribution, or use:

- Longmont, Colorado, on September 6, 2023
- Odessa, Texas, on September 7, 2023
- Williamsport, Pennsylvania, on September 12, 2023
- New York, New York, on September 14, 2023
- Port Arthur, Texas, on September 19, 2023
- Stonewall-Shreveport, Louisiana, on September 20, 2023

Participants were contacted and recruited using existing panel lists and social media and screened by SAGO or Plaza Research Corporation to include a mix of residents by gender, age, education, income, and partisan self-identification. Focus groups ranged in duration from 90 minutes to 105 minutes. Focus group participants recruited by SAGO received a cooperation incentive of $150, while those recruited by Plaza Research Corporation received $250.

The screener used to recruit focus group participants is included as Section V and the discussion guide used to conduct the focus groups is included as Section VI.

For more information about the study, please contact Hudson Pacific at info@hudsonpacific.co.

NPC FOCUS GROUPS REPORT

Can community engagement inform better outcomes?

Hudson Pacific conducted a series of six focus groups over the first three weeks of September 2023. The purpose of these focus groups was to explore the relationship between residents of energy-intensive communities (locales of natural gas production, distribution, and use) and assess whether engagement with these communities in advance of changes to industry policy or installation of new infrastructure might result in better outcomes.

One focus group each was conducted in the communities of:

- Longmont, Colorado
- Odessa, Texas
- Williamsport, Pennsylvania
- New York, New York
- Port Arthur, Texas
- Stonewall-Shreveport, Louisiana

The participants in each focus group were mixed demographically by gender, age, education, and race. Participants were members of the general public, not energy experts.

A. Setting Expectations

This last point about the participants is particularly important. We often find that our clients are so steeped in the issues they face that they expect the public to be at least aware, familiar with, and even engaged on a given issue. While they understand in abstract that not much information can break through when so much is competing for the public's attention, they are still surprised by what they hear in a focus group.

We need to hear the way people approach an issue and the language they use to talk about it, so we can meet them where they are. That is a prerequisite for trying to educate or engage them.

Conducting focus groups is an iterative process, not a linear one. Once we understand where

people are starting from, we can tailor the line of questioning to their knowledge and perspective. In cases where public awareness is especially low, we may have to ask indirect questions that get at their priorities and values, since it's hard for people to have well-formed opinions about something they haven't thought about before.

B. The Primary Research Question

Can engagement with energy-intensive communities lead to better decision-making and outcomes for the community and industry?

The public says yes, but it will require a significant commitment.

Project developers will need to defy public expectations if they hope to set a new standard for engagement. Interaction with communities in a considered way is not something residents have experienced to date. The industry also will need to work to overcome deep cynicism to convince people that community engagement can benefit everyone involved. Among other things, these focus groups revealed how effective engagement might work and the principles that should underpin the approach.

C. Engagement Is a Winning Concept

The *idea* of engagement appeals to people.

In theory, residents think energy-related infrastructure changes in their communities would be better with community engagement than without. They would expect the process to include companies exploring the needs of the community, listening to residents, understanding their perspectives, collaborating on solutions, and taking meaningful actions. Further, energy development that is more responsible (e.g., improvements in technology, alternative energy) likely would yield more, and better, engagement from a community. Changes at the margin would yield the opposite.

[I have a] preference for engagement with a company. And people are asking "What do I feel about this company?"... My opinion is going to change, because they put an effort forward, instead of just coming in and doing without trying to have that kind of dialogue or interaction with the people who live in (the community) and are going to be affected by what they're going to do. (Woman, Longmont, Colorado)

Let's say it's us, we're the community, we're so used to companies that just come in and do what they're going to do. And we deal with it. If you have one company that comes to [us] like, "Your opinion matters.... Tell me, talk to me, what you guys looking for?" We've never had that. (Woman, Longmont, Colorado)

The prospect of engagement buoyed and energized some residents.

Engagement would be a departure from residents' current experience. The possibility of being acknowledged, heard, and considered imbued them a palpable sense of agency, especially in the smaller communities we visited.

It was encouraging that you wanted our opinion on how to make things better. (Woman, Williamsport, Pennsylvania)

I think this is a great way to reach out to the community and get people's input. (Woman, Williamsport, Pennsylvania)

[W]e're different politically. And that didn't seem to matter. We could talk about this issue. (Woman, Williamsport, Pennsylvania)

I think it's encouraging that people care. I think it's encouraging that people want to have a voice. And I think if [companies] choose to listen to that, they'll find that there's a lot more people like us out there. (Man, Port Arthur, Texas)

I think it was really cool to see, you know, everybody from different walks of life, from different backgrounds, all have some type of form of what they want to see in the community. (Woman, Port Arthur, Texas)

That our input counts and we might begin to see where we interact more with the corporate organizations, the government, coming to the grassroots, and then everything will begin to trickle down and touch each and every one of us rather than a few individuals at the top. (Man, Port Arthur, Texas)

It feels like, in this day and age, everything is so politicized and to be able to come together and have a discussion where politics aren't [an issue] and it's just overall community involvement and community

betterment... that's really cool. (Woman, Port Arthur, Texas)

Benefits of engagement are not top-of-mind, but they aren't inaccessible.

Pressed for how companies might benefit, people readily identify improved relations with the community, better employee relations, reduced public opposition, and better government relations. That said, they had difficulty grasping potential for community benefits.

A community that might not go out and vote for people that are going to get rid of the gas industry. Yeah, they might benefit that way. And they might benefit from less opposition. And we wouldn't push to become New York and not allow any fracking at all. (Woman, Williamsport, Pennsylvania)

The energy industry is coming in for a lot of flak—nationwide—for a lot of reasons. And so, it might improve their reputation to be a solid community member—responsible about the environment, benefiting the community in different ways. (Woman, Williamsport, Pennsylvania)

I would say [they would] probably [engage] to gain the community's trust. (Woman, Port Arthur, Texas)

When people come together, and they're all in support of something you want, you want that backing, and that's gonna help in all kinds of ways as far as people wanting to work for them. (Woman, Williamsport, Pennsylvania)

I think they probably end up with more satisfied workers... (Man, Williamsport, Pennsylvania)

If the people saw that the big oil companies... are somewhat concerned about our environment, maybe that will get more people to care and get more involved about trying to help the environment. (Woman, Stonewall-Shreveport, Louisiana)

It sets a precedent. It's like, "Okay, this plant is asking for the community's involvement; we're gonna have to step up our game and show that we all want to be involved in the community." (Woman, Port Arthur, Texas)

The fact that "the company" would engage with the community would probably alleviate people's stress. The companies would engage with the community to see the community's side.... I think instead of just taking stuff on that they think may be a problem, or they think may make the community better, see what the community needs—really needs—to make it better. (Woman, Odessa, Texas)

Engagement isn't seen as exclusively a corporate responsibility: It is a shared one.

Residents in both the Longmont, CO, and Stonewall-Shreveport, LA, focus groups are correct in pointing out that government has a role in all of this as well (Figure C-1). They pointed out that voters have a say in these matters by way of voting for their elected representatives at the local, state, and federal levels who enact zoning ordinances, laws, and regulations that govern the siting, construction, and operation of the energy installations as well as any modifications or additional infrastructure. Companies receive their literal licenses to operate from these governmental bodies, but benefits exist from pursuing a social license to operate through the community engagement process.

D. Engagement Today

When we asked focus group participants, unaided, how oil and gas and other companies currently interact with their communities, their experiences did not resemble the engagement that sits atop the community engagement pyramid. Instead, we discovered a hierarchy that started with the most basic principle of a license to operate and built toward engagement (Figure C-2).

1. Regulated/Required

As discussed earlier, some Longmont and Stonewall-Shreveport residents described a license to operate that required only that operators followed zoning laws as well as local and state regulations. They did not think that a company was obligated to do anything beyond that. Why would they? Their job is to make money and anything more than gaining an institutional license to operate would be a waste of money.

If they're abiding by the laws and regulations, leave 'em alone, let them do their business. (Man, Longmont, Colorado)

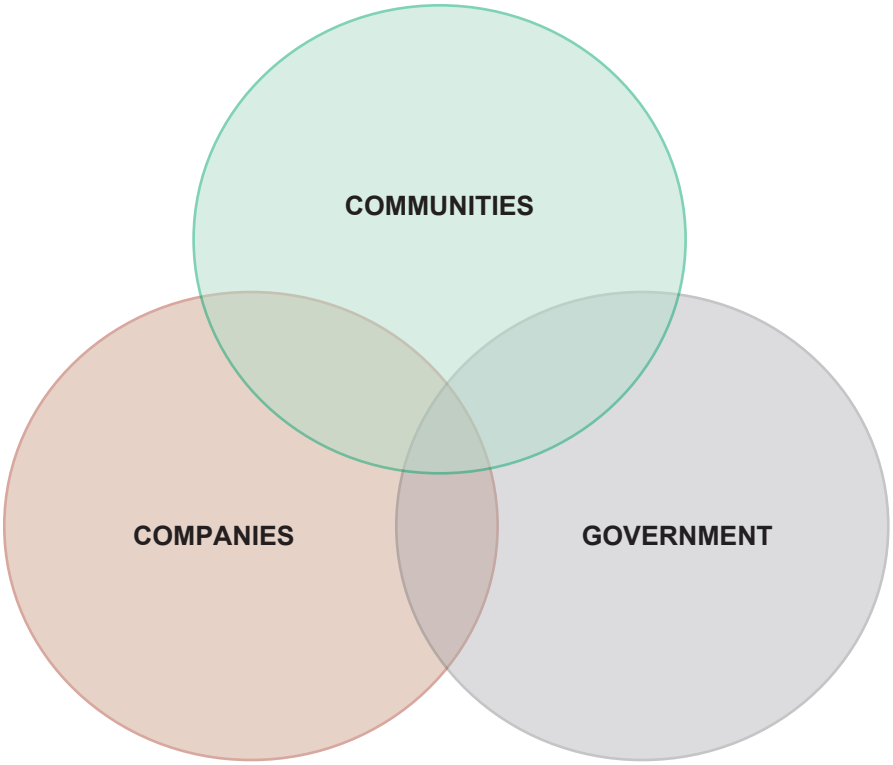


Figure C-1. *The Engagement Dynamics Between Communities, Companies, and Government*

You got a right to do what you want. I mean, as long as there's zoning laws involved.... If you agree with it, don't do anything. If you don't agree with it, you find what your zoning laws are, and you talk to the people that can change the zoning laws. (Man, Longmont, Colorado)

It's not the community's responsibility to make zoning laws, and it should go before the City Council. That's how they keep from throwing up an oil derrick in the middle of your neighborhood. (Man, Stonewall-Shreveport, Louisiana)

All that just adds cost to what they're doing. (Man, Stonewall-Shreveport, Louisiana)

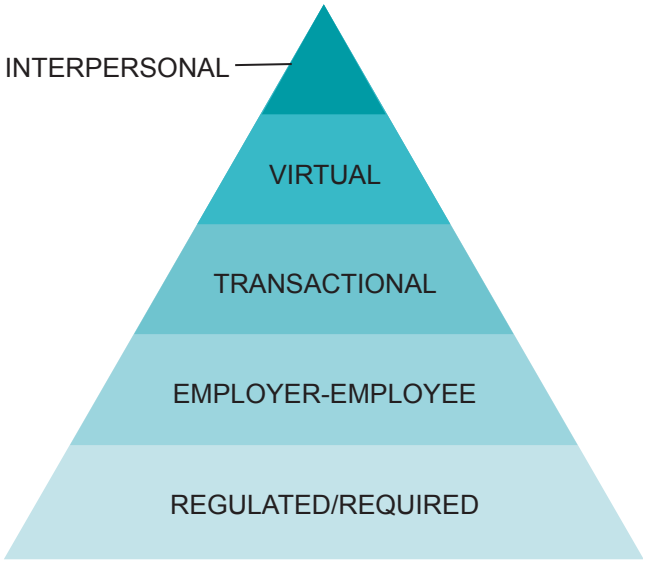


Figure C-2. *Hierarchy of Community Engagement*

2. Employer-Employee

With most residents, across geographies, the license to operate rested most heavily on whether a company was a good employer. Jobs functioned as social currency. Better jobs—those that are stable and offer benefits such as healthcare and a 401(k)—enhanced the reputation of the company that offered them.

It's about providing a living wage, full benefits, and full-time work. (Woman, Williamsport, Pennsylvania)

When you get hired, [the company] molds you. You're just not an employee. They teach you branding,

they make you proud of where you're working. (Man, Stonewall-Shreveport, Louisiana)

3. Transactional

This is what most people associate with engagement; something that goes beyond the employer-employee relationship. It involves companies giving back to the communities in which they operate, which can take the form of school programs, new or improved facilities, a fine arts center, or a park, among other things.

They've got to get creative and do things that the community wants. If they'd build a BMX track? That'd be huge. (Man, Longmont, Colorado)

They make donations. They give to St. Jude's. So yeah, they're involved in the community, they do baseball sponsorships. (Man, Stonewall-Shreveport, Louisiana)

They do go to the trade schools and sponsor jobs for them, like tuition or scholarship. (Woman, Stonewall-Shreveport, Louisiana)

While the transactional level comes closest, none of these bottom three levels of the pyramid involve the ongoing, two-way communications that characterizes true engagement.

4. Virtual

This does not offer the rich interaction that helps define the top of the pyramid, but virtual engagement does create an opportunity for a community to share input and feedback. We heard throughout the focus groups that this would be a necessary component when engaging younger generations, who are much more accustomed to engaging via social media platforms than in-person.

Social media... every neighborhood should have their own Instagram page. So, everybody can follow it and know what's going on. (Woman, New York, New York)

You can always have an online suggestion, especially with younger people. We're online all the time anymore on social media and stuff like that. So, if you just had a way to message questions or concerns, and then, if they did like an in-person townhall, they could go ahead and take from those ones that they want to answer. (Man, Williamsport, Pennsylvania)

5. Interpersonal

Asked about their experience with companies interacting with the community, participants described companies contributing to community needs, something we understand as a form of corporate social responsibility or being a good corporate citizen. When they did not have experience with an energy company engaging in this behavior, they offered examples of actions other companies had undertaken. Further, they generally had positive associations with how these companies give back to the community, but they also saw it as transactional and often self-serving.

A lot of the oil companies are out here trying to contribute really heavily. I mean, XTO, Pioneer, Chevron.… They try to contribute for the betterment of their companies and, you know, to make the community better so that people will want to come work for them and stay out here. (Woman, Odessa, Texas)

And then a bunch of the large companies [via the Permian Strategic Partnership] are trying to put money into better school systems. (Woman, Odessa, Texas)

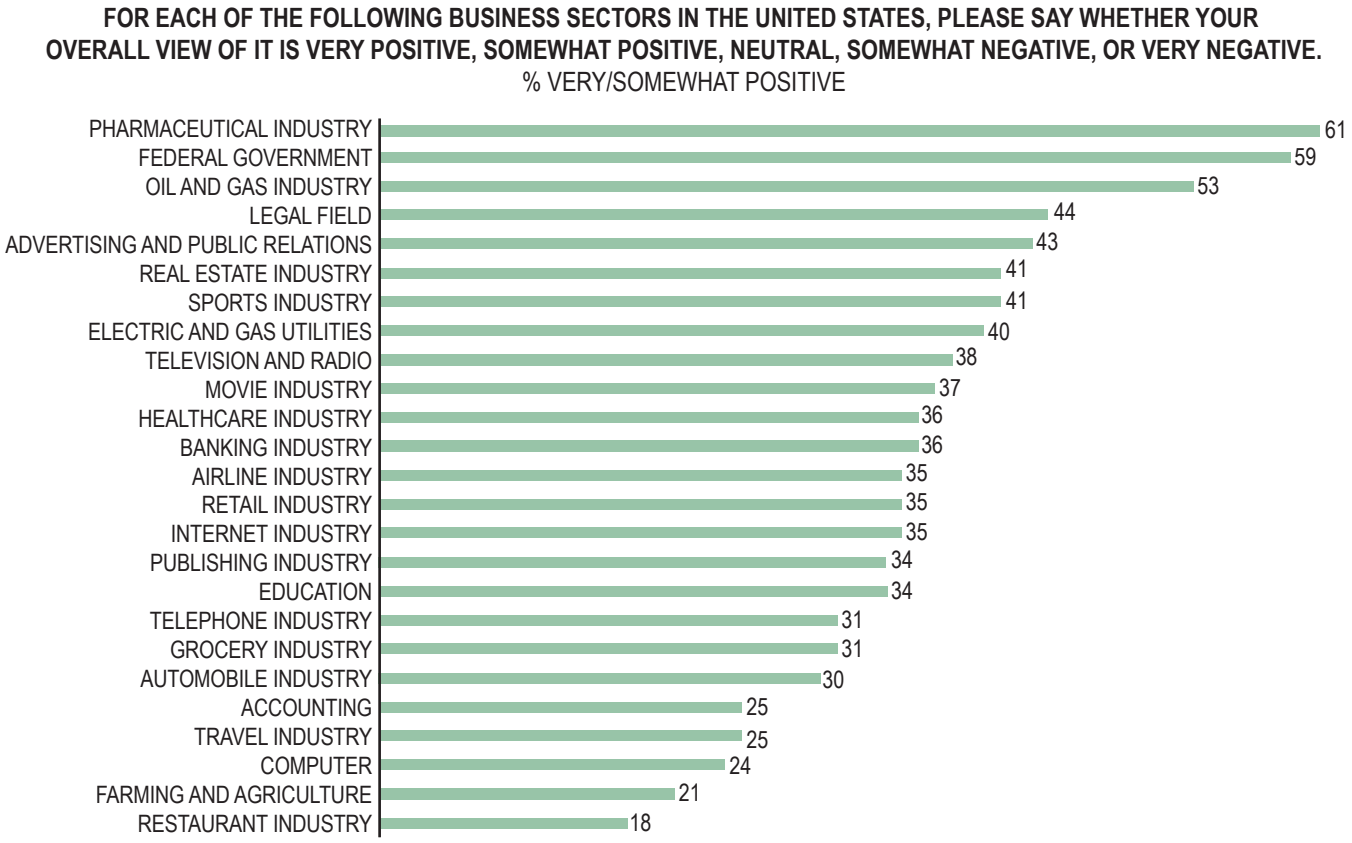
We get a lot of grants from local refineries that fund the education, because they're such big moneymakers. (Woman, Port Arthur, Texas)

[The local energy companies] care about community involvement whenever it benefits them in some way. But ... a lot of businesses operate that way.... So, a lot of the donations and grants that have been given to the college have been for industry-specific college students. Not to say that doesn't help those students in any kind of way. But it is kind of something to say, "Okay, well, we want these people that are coming into our plants and working for us to be educated, so we're going to give you money in order to help further those students' education." So not saying that it doesn't help out, but a lot of it is based on their own motives. (Woman, Port Arthur, Texas)

E. Obstacles to Rich Engagement

People are cynical about the prospect of corporate engagement.

Generally, this is consistent with annual Gallup polling on public confidence in societal institutions—large corporations typically rank near the bottom. In June of 2023, only 14% of



Source: Gallup, 2023.

Figure C-3. Public Confidence in Societal Institutions

adults in the United States said they have quite a lot or a great deal of confidence in large corporations, just six points higher than Congress, which received the lowest rating of 16 institutions.

Focus group participants think of corporations as primarily profit-seeking institutions that are reactive, not proactive, so they can't imagine companies would pursue engagement unless they needed to. While the cynicism should not be surprising, it can help to inform a serious and sober approach to engagement.

Meaningful engagement would need to be characterized by transparency, honesty, and authenticity. If approached in that manner, a company that engages in ongoing, two-way engagement could differentiate itself from competitors.

There was a small group of participants who questioned the need for engagement. Their views ranged from those who pondered why a company would go to such lengths to those who are downright hostile to the idea. Others wondered why a company would engage the community when it could accomplish its goals without engagement.

That's the thing; they're not looking for the involvement or the engagement with the community? They're just a business. (Man, Shreveport, Louisiana)

All that just adds cost to what they're doing. (Man, Shreveport, Louisiana)

In the end, companies need to clearly articulate the purpose of engagement. People don't expect, or even trust, that companies engage out of a sense of altruism (Figure C-3). Also, the novelty of the approach is partly to blame; it will be new to people and runs counter to the public perception of how companies operate. The best way for a company to inoculate itself against such skepticism is to acknowledge the novelty of the approach and be transparent and honest in what it hopes to achieve through the community engagement process.

People have a lot competing for their time and attention.

Engaging them would require a very high-profile issue or significant resources to raise the profile of an issue.

If you've ever heard the phrase, it doesn't have to happen to you for it to matter to you. It doesn't apply here. (Woman, Odessa, Texas)

The kind of "meh" attitude is everywhere. (Man, Odessa, Texas)

If it doesn't affect you, you're not going to [do] much unless it's like on my property.... But otherwise, I'm so busy with my day-to-day life, I'm not going out of my way. (Woman, Odessa, Texas)

F. Reactions to the Engagement Model

We used the process described in this section as a model for engagement in these focus groups (Figure C-4). Ideally, engagement is an ongoing cycle that begins with thoughtful exploration and is further characterized by dialogue, internalization, collaboration, and visible outcomes.

We broke down our proposed engagement model one step at a time and discussed each phase to discover how residents interpreted each. It is worth noting here that engagement cannot take a one-size-fits-all approach for every community. Determining whether, and to what degree, to engage a community should be assessed in the initial phase of the model.

1. Prepare: Learn About Our Community and Our Needs

If they want that open communication, that engagement that you're talking about then, you know, know something about me and my goals and my community. If you're coming into my community, you should have done your homework about where we feel like we're headed and say, "This is how we're going to help with that vision for your community." (Woman, Longmont, Colorado)

2. Listen: A Profound Desire to Be Heard

I think the best way they can do that is by talking to the community, asking them what they need, whether that be talking to the government, holding town halls. "Hey, we want to help impact the community." (Man, Port Arthur, Texas)

It's important that they don't say, in their corporate office, "We're going to have a meeting with our executives and go 'alright, let's target this area.'" Why don't you go ask the community what they need, and let the community tell you what they need, and what you can do to help? (Man, Port Arthur, Texas)

3. Understand & Learn: A Dialogue

I think the most important thing about any type of engagement is to understand the needs of both sides and make sure it's a healthy and productive engagement. (Man, Port Arthur, Texas)

They could do research... put out a questionnaire. People can [complete the survey] and then they assess

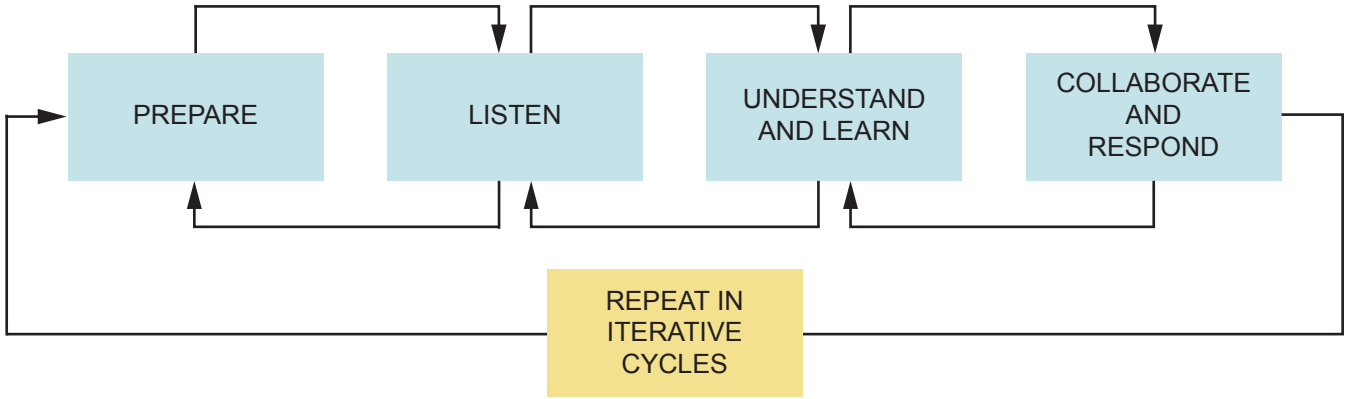


Figure C-4. *Community Engagement Model*

it statistically; these are the needs of the community. [participant]

4. Collaborate & Respond: A Willingness to Work Together and Take Action

[They should take] action. That means changing. Saying that, "Okay, this is a concern, and this is what we're doing about it. This is how we're addressing the problems that people have with certain aspects of the industry." (Woman, Williamsport, Pennsylvania)

They better be serious, because for the people that are sitting back saying, "Well, I don't really think it matters," and you convince them…. Then [if] the company doesn't follow through on that stuff, then I think it will set you back further. (Man, Port Arthur, Texas)

5. Repeat Iteratively

They need to stay active in the community. (Woman, Williamsport, Pennsylvania)

G. Prerequisites for Effective Engagement

1. Transparency

I want information on what you're telling me. I want you to be as transparent as you can; tell me what's going to go on. And allow me to ask questions, allow me to get more information. Instead of having, like you're saying, to do the research on my own, I want you to come into my community, you're coming into my community, then it's your responsibility to tell me what you're doing and what my options are. And to share... (Woman, Longmont, Colorado)

If I felt like they were being honest and transparent... [trust could be rebuilt]. (Woman, Williamsport, Pennsylvania)

There's a lot of reasons why they might [want to engage the community]. And some of them aren't the most ethical. So sometimes it's the easiest to say, "This is why we want to do this." (Man, Port Arthur, Texas)

2. Accountability

It would just be so refreshing if a company said, "We screwed up. We were wrong. We made a mistake. This was wrong." You know, it's just nobody seems to want to take responsibility or accountability for mistakes, and I won't condemn somebody for making a mistake. (Woman, Williamsport, Pennsylvania)

I think it kind of goes back to the accountability again, and making sure that, you know, things are actually happening as they're supposed to. (Man, Williamsport, Pennsylvania)

There's an even more important side of engagement. That's accountability. Because I think that they want to just kind of throw money in certain different charities. But for example, the environmental impacts, they need to take accountability for that. And oil companies have been some of the worst—certainly not the only, a lot of energy industry people are like this, but a lot of other industries as well. They don't want to own up to the amount of damage they're doing to the environment, the amount of damage they're doing to communities, they don't they want to, you know, turn to either the blame elsewhere, or they want to say, well, even if it is true, it's not our responsibility to fix it. But it you know, but isn't it though? I mean, on just a man-to-man level, maybe it's not your responsibility legally. Shouldn't you engage a little bit? And I think taking that accountability would mean as much as the monetary, whatever that would be that they're putting into the community...now. (Man, Port Arthur, Texas)

3. Respect

As long as I can voice my concern, and at least be heard and respected for what I say. (Man, Williamsport, Pennsylvania)

And what you want to do is you want to make sure that you're being heard, but you're also being heard but taken seriously. (Man, Williamsport, Pennsylvania)

So, your voice can be heard, too. I mean, that is not that hard. It does not cost that much, especially on the scale that they need to do it and the amount of money they have, that is pretty cheap. (Man, Port Arthur, Texas)

[Community members] want to be heard. (Woman, Shreveport, Louisiana)

4. Acknowledging Fear of Change

In several of the groups, residents mentioned that "people don't like change." It was an interesting social observation that seemed to come out of nowhere but is worth keeping in mind. It arose in Port Arthur, Texas, as we were discussing potential trade-offs between emissions reductions and

employment, which also coincided with a desire for someone as senior in a company as possible to attend a town hall to answer questions from the residents.

I don't think it's so much trust as change. People don't like change. Gotta build that... bring it in and try it out; people here don't like change. (Woman, Williamsport, Pennsylvania)

I think having paved the way that they are, and if you were to change to more environmentally friendly things, you would see a lot of backlash because people don't usually like change. (Woman, Port Arthur, Texas)

People are not ready for change and some people are ready for change. So, you need to inform your community, and then maybe they'll be more welcoming. (Woman, Shreveport, Louisiana)

I will say that age of the community that is living in the area, because sometimes the older people, they don't want to hear it, they don't want it, they don't want change. (Woman, Shreveport, Louisiana)

5. Reaching People to Engage Them

I don't think you're going to be able to ever reach all of the people. Just like with anything, there's just people who, for whatever reason, whether it's they don't care, or they they're too busy, or whatever's going on in their life, you're just not going to reach them. But if you reach a majority of the people, I think that you do your very best to reach everybody that you can. (Woman, Williamsport, Pennsylvania)

[The company] has to go into it with that mentality, "They're not going to believe us until they see it." And if you're honest, then we'll see it. And again, it will be worth it. (Woman, Longmont, Colorado)

V. FOCUS GROUP PARTICIPANT SCREENING QUESTIONNAIRE

Recruit a mix of 10 for 8

Name: _____

Email: _____

Phone: _____ Recruiter: _____

Hello, my name is _____ and I work for _____, a local research firm. We'd like to invite you to participate in an interesting research study on DATE at TIME. There will be a 2-hour group discussion and participants will be paid $125. If you are interested, and available, I'd like to ask you a few questions.

[IF NECESSARY] Please be assured that we are not selling anything, and the information gathered will remain confidential and be used for research purposes only.

1. [DO NOT ASK, INTERVIEWER RECORD]

❒ Male	**RECRUIT 5**
❒ Female	**RECRUIT 5**

Do you, or does anyone in your household, work in advertising, marketing, public relations, the news media, or political campaigns?

❒ Yes	**THANK AND TERMINATE**
❒ No	

When was the last time you participated in a focus group, if ever?

❒ Less than 1 year	**THANK AND TERMINATE**
❒ One year or more	
❒ Never	

What is your age?

❒ Under 18	**THANK AND TERMINATE**
❒ 18 to 24 years	**RECRUIT 1-2**
❒ 25 to 34 years	**RECRUIT 1-3**
❒ 35 to 44 years	**RECRUIT 2-3**
❒ 45 to 54 years	**RECRUIT 2-3**
❒ 55 to 64	**RECRUIT 1-3**
❒ 65 and older	**RECRUIT 1-2**

What is the highest level of education that you have completed?

❒ Less than high school	**THANK AND TERMINATE**
❒ High school/GED	**RECRUIT 3-4**
❒ Some college/2-yr/trade school degree	**RECRUIT 3-4**
❒ 4-yr college degree or more	**RECRUIT 3-4**

Are you:

- ❒ Employed full time
- ❒ Employed part time
- ❒ A homemaker — **RECRUIT 1 OR FEWER**
- ❒ Retired — **RECRUIT 1 OR FEWER**
- ❒ Currently unemployed
- ❒ A student — **RECRUIT 1 OR FEWER**

What is your occupation?

_____ [BE SPECIFIC]
[RECRUIT NO MORE THAN 2 FROM A SPECIFIC INDUSTRY]

I am going to read a few ranges of annual household income; please stop me when you hear the range that best describes your overall family income.

- ❒ Less than $35,000 — **RECRUIT 1-2**
- ❒ $35,000 to less than $50,000 — **RECRUIT 1-3**
- ❒ $50,000 to less than $75,000 — **RECRUIT 2-3**
- ❒ $75,000 to $100,000 — **RECRUIT 2-3**
- ❒ $100,000 to less than $150,000 — **RECRUIT 1-3**
- ❒ $150,000 or more — **RECRUIT 1-3**

Are you white, Black or African-American, Hispanic, Asian, or something else?

- ❒ White — **RECRUIT 3-4**
- ❒ Black or African-American — **RECRUIT 2-3**
- ❒ Hispanic — **RECRUIT 3-4**
- ❒ Asian — **RECRUIT 0-1**
- ❒ Something else (Specify:_____) — **RECRUIT 0-1**

Are you currently registered to vote at this address?

- ❒ Yes
- ❒ No
- ❒ Registered elsewhere
- ❒ [DO NOT READ] Don't know

In politics today, do you consider yourself to be a Republican or Democrat? [IF INDEPENDENT] Would you say that you lean Republican or lean Democrat?

- ❒ REPUBLICAN — **RECRUIT 3-4**
- ❒ Strong Republican
- ❒ Not-so-strong Republican

- ❒ INDEPENDENT — **RECRUIT 3-4**
- ❒ Independent lean Republican
- ❒ Independent lean Democrat

❒ DEMOCRAT — **RECRUIT 3-4**
❒ Strong Democrat
❒ Not-so-strong Democrat

❒ [DO NOT READ] OTHER — [SPECIFY]
❒ Don't know — **THANK AND TERMINATE**
❒ Refused — **THANK AND TERMINATE**

Do you have children in your household under the age of 18? [IF YES] How many children under the age of 18 do you have?

❒ No children — **CONTINUE**
❒ 1-2 children
❒ 3-4 children
❒ 5 children or more

How interested would you say you are in politics and public policy issues? Would you say you are… [READ 1-4]

❒ Very interested
❒ Somewhat interested
❒ Not very interested — **SEE BELOW**
❒ Not at all interested — **SEE BELOW**
❒ [DO NOT READ] Don't know — **THANK AND TERMINATE**
❒ [DO NOT READ] Refused — **THANK AND TERMINATE**

[PLEASE RECRUIT AT LEAST FOUR RESPONDENTS WHO ARE VERY OR SOMEWHAT INTERESTED.]

Thinking again about the news, from what sources do you get news and information on national public policy issues? [ASK OPEN ENDED]

❒ Local newspaper
❒ National newspapers
(NYT, Washington Post, LA Times, WSJ)
❒ News sites online [PROBE FOR SPECIFICS]
❒ Local television news
❒ Cable news channels [WHICH?]
  ❒ Fox
  ❒ NEWSMAX or OAN
  ❒ CNN, MSNBC
  ❒ Network news such on ABC, NBC, or CBS
  ❒ C-SPAN
  ❒ Sunday morning news shows
❒ Internet [PROBE FOR SPECIFIC WEBSITES]

❒ Social Media
  ❒ Facebook
  ❒ X/Twitter
  ❒ Truth Social
  ❒ OTHER [PROBE FOR SPECIFICS] _____

❒ [DO NOT READ] None of these
❒ [DO NOT READ] Don't know
❒ [DO NOT READ] Refused

[AT LEAST HALF MUST SELECT AT LEAST TWO OPTIONS. READING ONLINE COUNTS.]

One last question, and changing the subject a little bit, I'd like you to think for a moment about what some of the major issues facing our country are today, aside from the country's economic situation. [FOR EACH ISSUE MENTIONED, ASK: What do you think should be done on this issue? Why do you feel that way?] [PROBE FOR SEVERAL ISSUES. WRITE DOWN RESPONSE AS CLOSE TO VERBATIM AS POSSIBLE.]

_____

_____

_____

_____

[**Note: The purpose of this question is to make sure that the respondent is articulate.** If respondent gives a very brief answer or says, "I don't know," or seems uncomfortable talking to the interviewer, terminate. If the respondent is not fully fluent in English, terminate.]

INVITATION:

We would like to invite you to participate in our discussion group on DATE at TIME at the LOCATION. The discussion will take approximately 2 hours of your time and you will receive $250.

Your participation is confidential and let me assure you that no one will try to sell you anything; this is strictly for research purposes.

Will you be available on DATE at TIME?

❒ Yes **RE-CONFIRM ADDRESS AND TELEPHONE**
❒ No **THANK & TERMINATE**

Offer Location & Directions to Facility

VI. FOCUS GROUP DISCUSSION GUIDE

September 2023 • Various Locations

INTRODUCTION – 10 MINS [TRT 10 MINS]

Thank you for coming

Moderator introduction

A listening, not a sales exercise

No right or wrong answers

Explain room layout (mics, video, mirror)

Confidential, research only

Paper and pen exercises, thought exercises

Participant introduction:

- How long have you lived in the area?
- What do you do?

LOCAL ISSUES AND INDUSTRY - 15 MINS [TRT 25:00]

- What drew you to live here? Do you consider this home?
- What are some of the important issues facing your local community at the present time?

[WRITE THEN DISCUSS] Which industries come to mind as being a big part of your local community?

What associations do you have with these industries, positive, negative, or otherwise?

- Why?
- How do these industries benefit your community?
- Any drawbacks? [IF YES, ASK] Do they do more good than harm?

What does responsible behavior look like when it comes to an industry operating in a community? What do you expect from a responsible industry or company?

ENERGY INDUSTRY – 15 MINS [TRT 40:00]

We're going to focus on the energy industry for the rest of the evening.

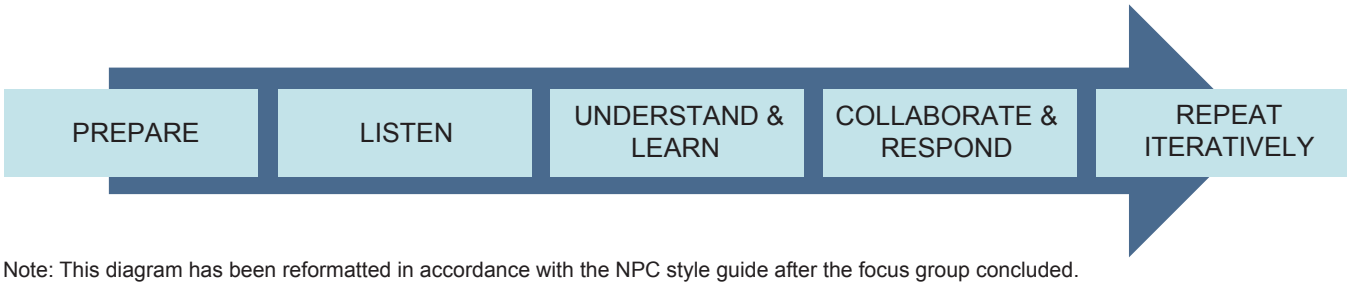
- Do you think of the energy industry as a big part of this community?
  - Why? [PROBE AS NEEDED]
  - It's everywhere?
    - Trucks and equipment?
    - Know people who work there?
    - News and attention it has generated?
    - Adverse events happen?

    - We benefit as a community?
    - It has brought wealth?
    - It has brought environmental degradation?
  - Why not? [PROBE AS NEEDED]
  - It's invisible?
  - We're just used to it?
  - It's just another industry/employer?
  - It's bigger elsewhere?
- What is the nature of the energy industry? What does it include? What has the greatest impact on the area?
  - Utility?
  - Production?
  - Transport/Distribution?
- What local energy companies come to mind?
- What is the nature of your relationship/connection to the energy industry, if any? [PROBE FOR SPECIFICS]
  - Family (you/family member work in the industry)?
  - Friends and neighbors work in the industry?
  - Children benefit from energy sponsorship some way?
  - Live in a fenceline community or otherwise in proximity?
  - How close do you live to energy operations?
  - Aware that it contributes to the economy? How/how much?
  - Just aware that it's there, but no direct or indirect connection?
  - How does its presence affect your life?
    - Advantages?
    - Disadvantages?
  - Overall, a net plus, or a net minus?
  - And what about compared to other industries in the area?
  - Within the larger energy-intensive geography, do you think burdens and benefits are shared equally by different segments of the population?
    - [IF NO] Are you aware of efforts to account for differences?
  - Would your attitude/opinion be different if the energy infrastructure in question were for cleaner energy and a cleaner world?

INDUSTRY ENGAGEMENT – 20 MINS [TRT 60:00]

- What kind of relationship do local energy companies have with residents?
- How do local energy companies interact with the community?
  - Share information?
  - Otherwise communicate with the community?
  - Seek input from the community?
  - Look out for the best interests of the community?
  - Consider the community's values when making decisions
- What does "engagement" mean to you when it comes to interactions between an industry or company and a community where it operates?
  - What examples come to mind, if any?
  - How would you characterize "engagement?"
- Have local companies tried to engage with the community?
  - [IF YES] What has worked and what hasn't?
  - What opportunities exist for meaningful engagement on issues related to the energy industry?
  - What opportunities exist to offer input or feedback about a new project?
  - If you wanted to, how would you go about offering feedback?
  - What ideas do you have that could improve engagement?
    - Do you feel like you have a voice in what happens in your community?
    - Do you feel heard or does it feel like a check-the-box situation?
    - Are there ways for you to offer input?
    - Is there communication? One-way? Two-way?
    - Is a "relationship" possible?
    - What would make you feel like you have been engaged?
    - Does this even matter to you? Do you care? (purposely provocative)
    - Are you resigned to a transactional relationship? (extraction colony)
- Would improved engagement affect you? If so, how?
- Would improved engagement affect the energy company? If so, how?
- Would improved engagement affect the relationship between the community and the energy industry? If so, how?

Here is an engagement model (Figure C-5)... Does this look like engagement to you?



Note: This diagram has been reformatted in accordance with the NPC style guide after the focus group concluded.

Figure C-5. *Image Used in Focus Groups to Represent the Community Engagement Model*

INFORMATION SOURCES – 15 MIN [TRT 75:00]

How do you learn about new projects or developments in your community?

Where do you get your news and information? What are the sources of information you trust most in your community?

- [IF INTERNET] Where do you go specifically?
- Friends and family?
- Local news outlets?

When there is important news in the community, whom do you look to for validation? Who are the trusted sources of information in the community?

- Local elected officials?
- Religious leaders?
- Business leaders?

LIFE DECISIONS & TRADE-OFFS – 15 MINS [TRT 90:00]

1. Back to a question that I asked at the outset: How did you come to live here in the area? I'm going to give you some examples, but I'd like you to take a few minutes and make some notes for yourself about the story of how you came to live where you do. Decision-making is complex; you consciously or subconsciously take several competing factors into consideration. I'm asking you to take this one big decision and deconstruct it to the degree that you can in the short amount of time you have here.

- What factors did you take into consideration?
- What trade-offs, implicit or explicit did you make to reach your decision?
  - Were there sacrifices you had to make?
  - What compromises did you make?

Is this a good place to raise a family? Is this an area where you would like to see your children stay and raise a family or would you like to see them move on?

Now, I'd like you to think about a couple of hypothetical decisions…

- A policy decision that could significantly improve the air quality in your community, reducing respiratory diseases, but it could reduce employment in the energy industry in the area through greater efficiency or cost cutting.
- A policy change that would improve the health of your children, but might cost you your job.
- A necessary reduction in greenhouse gas (GHG) emissions that would result in a 25% reduction in employment where you work.
- An opportunity for your child in the energy industry where you live, another industry in your community, or an opportunity in another industry elsewhere.
- A reduction in GHG emissions, which would result in improved health for your family, but increase your monthly utility bill by 10 to 20 percent.

CONCLUSION – 10 MINS [TRT 100:00]

- What was the most compelling piece of information you learned tonight? Why?

Thank you for coming.

305 EAST 5TH STREET,
ODESSA, TEXAS, USA, 79761

VII. POLLING INSTRUMENT (SURVEY) AND REPORT

A. Poll Methodology Statement

This study was sponsored by ClearPath and conducted on behalf of the National Petroleum Council by Hudson Pacific. The results are based on an online survey of 1,000 adults aged 18 and up, who reside in states where natural gas is produced and/or a natural gas distribution terminal is sited. Surveys were collected in English between October 27 and November 13, 2023. The survey was preceded by six in-person focus groups conducted in communities where natural gas is produced and/or a natural gas distribution terminal is sited between September 7 and 20, 2023.

B. The Online Survey

Surveys were completed by 800 adult residents of counties in the top eight natural gas-producing states in the continental United States and 200 residents of counties where natural gas terminals are sited (Table C-1). The residents were adults (18+) who were screened to exclude those not aware the natural gas industry was operating in their community. Interviews in production communities were distributed by county within states, proportionate to the relative levels of natural gas production (See Table C-1).

Demographic quotas for age and gender were imposed for representativeness. As with all surveys, this poll may be subject to methodological errors, including coverage, nonresponse, and measurement errors. Because the survey did not utilize a probability sample, no estimates of sampling error have been calculated.

Fieldwork was conducted online by The Logit Group, Inc. using its prerecruited, general-public panel network recruited using a double opt-in methodology. Panelists are incentivized digitally/electronically, in the form of points that are then converted and redeemed into cash or "near cash" (gift cards). The number of points awarded per survey depends on survey length, qualification, etc.

Survey length averaged 12.5 minutes. Procedures to ensure data quality excluded "speeders" or respondents who "straight lined" their responses as well as monitoring of IP addresses to prevent bots or survey farms.

The survey instrument (questionnaire) used by respondents is included as Section VIII.

State	Typical Monthly Gas Production – BCF	% of National Production	Adjusted % of Production	Number of Interviews
Texas	930	28	29	232
Pennsylvania	634	18	19	152
Ohio	536	5	16	128
Louisiana	277	8	8	64
New Mexico	265	8	8	64
West Virginia	237	7	7	56
Colorado	175	5	6	56
Oklahoma	216	4	7	48

Table C-1. *Distribution of Poll Respondents by State*

VIII. NPC ENGAGEMENT SURVEY

October 11, 2023

Survey of a sample of 1,000 adults—800 in oil and gas production communities and 200 in natural gas terminal communities.

SCREENING QUESTIONS

In what zip code do you currently reside?

[LIST OF ZIP CODES PROVIDED]
What is your age?

[RECORD ACTUAL, CODE AS:]

❒ 18 – 34

❒ 35 – 49

❒ 50 – 64

❒ 65+

Do you or does anyone in your household work in any of the following:

❒ Advertising or public relations [TERMINATE]

❒ Marketing [TERMINATE]

❒ News media [TERMINATE]

❒ Political campaigns [TERMINATE]

❒ Electric utility [CONTINUE]

❒ Energy [CONTINUE]

❒ None of the above [CONTINUE]

What is your gender?

❒ Male

❒ Female

❒ Non-binary

❒ Other

❒ Prefer not to answer

LOCAL CONDITIONS

Q1: Please indicate whether each of the following industries operates in or near your community:

[RANDOMIZE]

❒ Oil and natural gas
(not including your local gas station)

❒ Tourism

❒ Information technology

❒ Healthcare

❒ Manufacturing

❒ Transportation

❒ Agriculture

❒ Yes

❒ No

❒ Don't know

❒ [CONTINUE IF RESPONDENT INDICATES OIL AND GAS INDUSTRY IS OPERATING IN THEIR COMMUNITY]

Q2: How satisfied are you with each of the following in your community?

[RANDOMIZE]

❒ The current economy

❒ Quality of life

❒ Job opportunities

❒ Economic stability

❒ Educational opportunities

❒ Condition of local air, water, and land

❒ Very satisfied

❒ Somewhat satisfied

❒ Somewhat dissatisfied

❒ Very dissatisfied

INDUSTRY IMPORTANCE AND ASSOCIATIONS

Q3: Please rate the role each of the following industries plays in your community.

[REPEAT ORDER IN Q1; ONLY INDUSTRIES OPERATING LOCALLY]

❒ Oil and natural gas
(not including your local gas station)

❒ Tourism

❒ Information technology

❒ Healthcare

❒ Manufacturing

❒ Transportation

❒ Agriculture

❒ Very important

❒ Somewhat important

❒ Not very important

❒ Not at all important

❒ Not aware of this industry in the area

❒ Don't know

Q4: Which of these industries is the most important to your town's economy, or are they about equally important?

[SHOW LIST FROM Q3 RATED IMPORTANT]

❒ They are about equally important

Please select **all** of the following statements that describe you.

❒ I am employed in the oil and gas industry.

❒ Someone in my family employed in the oil and gas industry.

❒ I have a friend or neighbor employed in the oil and gas industry.

❒ I live within five miles of an oil and gas industry facility.

❒ I receive compensation or royalty payments from an oil or gas company.

❒ None of these apply to me.

INDUSTRY RATINGS

Q5: Generally speaking, do you have a favorable or unfavorable opinion of how the oil and gas industry operates in your community?

❒ Very favorable

❒ Somewhat favorable

❒ Neutral

❒ Somewhat unfavorable

❒ Strongly unfavorable

❒ Don't know

[IF Q5=FAVORABLE, ASK:] Why do you have a FAVORABLE opinion of how the oil and gas industry operates in your community?

_____

_____

_____

_____

[IF Q5=UNFAVORABLE, ASK:] Why do you have an UNFAVORABLE opinion of how the oil and gas industry operates in your community?

_____

_____

_____

_____

Q6: How much do you trust the oil and gas industry to do the right thing for your community?

❒ A great deal

❒ Somewhat

❒ Not very much

❒ Not at all

INDUSTRY OUTREACH

Q7: As far as you know, have the oil and gas companies in your area done any of the following outreach? Please select all that apply.

[RANDOMIZE]

- ❒ Sent a flyer about their operations or work they are planning in the area
- ❒ Held a community meeting or town hall
- ❒ Made a donation or provided support to educational institutions in the area
- ❒ Made a donation or provided support to a local charity
- ❒ Invited you to offer feedback on work they are doing in the area
- ❒ Explored community needs and priorities, and then assisted the community to meet those needs
- ❒ Made a donation or helped staff events in town, such as a sporting event or parade
- ❒ Sought feedback from the community about their operations
- ❒ Engaged the community to solve a local problem
- ❒ Reached out to you personally for input
- ❒ Shared informational materials about safety measures in and around their facilities
- ❒ Some other outreach [PLEASE SPECIFY]
- ❒ None of these
- ❒ I am not aware

Next, I would like to focus on natural gas—that includes the natural gas that many people use to fuel their furnace, hot water heater, and stove, and electricity generated by natural gas. Natural gas is distributed through infrastructure such as pipelines.

Imagine a situation where a natural gas company wants to install new energy equipment or infrastructure in your area. The project has the potential to both positively and negatively impact your community.

Q8: For each of the actions the natural gas company could take related to the project, which would be most likely to improve your opinion of the company? Which would be the least likely?

[MAX DIFF EXERCISE – SHOW A RANDOM SUBSET OF THE FOLLOWING]

- ❒ Learn about the needs of the community before launching the project
- ❒ Seek community input about ways to mitigate impacts from the project
- ❒ Collaborate to address overall community concerns
- ❒ Communicate with the public regularly and transparently
- ❒ Operate with accountability—follow through on promises and accept responsibility if anything goes wrong
- ❒ Invest in the health and future of the community, regardless of whether the company will continue to operate there
- ❒ Respect the community and act as a good neighbor
- ❒ Hire community members to work on the project

[RANDOMIZE Q9-14]

Q9: Thinking again about the natural gas company wanting to install new energy equipment or infrastructure in your area, would you be willing or unwilling to have a natural gas pipeline built in your neighborhood if you knew that it included new technology that reduced greenhouse gas emissions globally?

❒ Willing

❒ Unwilling

❒ Not sure

Q10: Would you be willing to have a new natural gas pipeline run through your neighborhood if it lowered your energy bill?

❒ Yes

❒ Maybe

❒ No

Q11: [IF Q10 = YES OR MAYBE, ASK:] How much of a discount on your energy bill would you expect if a new natural gas pipeline were built through your neighborhood?

❒ _____ % discount

❒ Not sure

Q12: Would you be willing to have a new natural gas pipeline run through your neighborhood if it provided jobs and other economic benefits to your community?

❒ Yes

❒ Maybe

❒ No

Q13: Assume your energy bills are $100 per month. How much more per month would you be willing to pay for energy if it contributed to certifiably cleaner air, water, and land resources?

❒ $10

❒ $20

❒ $50

❒ Would not be willing to pay more

Q14: What would be a reasonable monthly increase in what you pay for electricity to cover the cost of new technology that would help reduce carbon emissions from natural gas and limit rising global temperatures in the future.

❒ $_____ per month

❒ Would not be willing to pay more

ENVIRONMENTAL JUSTICE

Q15: When it comes to ensuring that the benefits of natural gas development are fairly distributed in a community, how much of a role do you think each of the following organizations should have?

[RANDOMIZE]

❒ Department of Energy

❒ Your state government

❒ Your local government

❒ Local college and university experts

❒ The oil and gas industry

❒ An advisory group made up of representative community members

❒ An outside, third-party organization

❒ Major role

❒ Minor role

❒ No role at all

❒ Don't know

[ROTATE Q16-17 & Q19-20]

Q16: When it comes to oil and gas operations in your region, who benefits most?

❒ People who live in the community

❒ People who live outside the community

❒ Don't know

Q17: When it comes to oil and gas operations in your region, do you think the BENEFITS of oil and gas operations have been distributed fairly across the community OR do you think certain parts of your region have seen fewer BENEFITS?

[ROTATE]

❒ Benefits are distributed fairly

❒ Benefits are distributed unfairly

❒ Don't know

Q18: [IF Q17 = UNFAIRLY, ASK:] Who is benefitting the most from oil and gas operations in your region?

_____

_____

Q19: When it comes to oil and gas operations in your region, who experiences most of the negative impacts?

❒ People who live in the region

❒ People who live outside the region

❒ Don't know

Q20: When it comes to oil and gas operations in your region, do you think the DOWNSIDES of oil and gas operations have been distributed fairly across the region OR do you think certain parts of your region have seen more DOWNSIDES?

[ROTATE]

❒ Downsides are distributed fairly

❒ Downsides are distributed unfairly

❒ Don't know

Q21: [IF Q20 = UNFAIRLY, ASK:] Who is negatively impacted by oil and gas operations in your region the MOST?

_____

_____

Q22: [IF Q20=UNFAIRLY, ASK:] Do you think efforts should be made to ensure that the benefits and costs of future energy developments are distributed more fairly in the community?

❒ Yes

❒ No

Q23: [IF Q20=UNFAIRLY, ASK:] With regard to the impacts of past oil and gas operations in your area, do you think you think efforts should be made to ensure benefits for those residents who experienced more than their fair share of costs?

❒ Yes

❒ No

ADDITIONAL DEMOGRAPHICS

Q24: What is the last grade of school you completed?

❒ High school or less (grades 1-11)

❒ Graduated high school (grade 12)

❒ Vocational school/technical school

❒ Some college

❒ Graduated college

❒ Post-graduate degree (e.g., MA, MBA, LLD, PhD)

❒ Prefer not to answer

Q25: Is your racial or ethnic heritage white, Black, Hispanic, Asian, mixed, or something else?

❒ White

❒ Black

❒ Hispanic

❒ Asian

❒ Mixed

❒ Other [VOL]

❒ Prefer not to answer

Q26: Generally speaking, do you think of yourself as a Republican, a Democrat, an Independent, or something else?

❒ Strong Democrat

❒ Not very strong Democrat

❒ Independent/lean Democrat

❒ Strictly Independent

❒ Independent/lean Republican

❒ Not very strong Republican

❒ Strong Republican

❒ Other

❒ None of these

Q27: Which of the following income groups includes your estimated TOTAL FAMILY INCOME in 2022 before taxes?

❒ Less than $20,000

❒ $20,000 to under $30,000

❒ $30,000 to under $40,000

❒ $40,000 to under $75,000

❒ $75,000 to under $100,000

❒ $100,000 to under $200,000

❒ $200,000 or more

❒ Prefer not to answer

IX. ADDITIONAL REFERENCES AND RESOURCES

A. Health Risks and Impacts

- Box 3-2 in the National Academy of Sciences' 2023 decarbonization report provides references on health risks from future climate extremes: National Academies of Sciences, Engineering, and Medicine. 2023. Accelerating Decarbonization in the United States: Technology, Policy, and Societal Dimensions. Washington, D.C.: The National Academies Press. https://doi.org/10.17226/25931.

B. Community & Stakeholder Engagement

Note this is not an exhaustive list but intended to give the reader multiple resources that have been developed to guide community and stakeholder engagement process.

- "Climate Equity Framework and Toolkit for an Equitable Energy Transition in Greater Houston." April 2024. https://htxenergytransition.org/wp-content/uploads/2024/04/04.02.24_Climate-Equity-Report.pdf.
- "API Recommended Practice (RP) 1185 Pipeline Public Engagement." 2024. https://publications.api.org/documents/1185_e1-PubAcc/html5.html.
- "API RP 100-3 Community Engagement Guidelines API Publishes Community and Stakeholder Engagement Standard for Upstream Operations." April 4, 2024. https://www.api.org/news-policy-and-issues/news/2024/04/04/api-publishes-community-stakeholder-engagement-standard-upstream-operations.
- Federal Energy Regulatory Commission. "Suggested Best Practices for Industry Outreach Programs to Stakeholders." July 2015. https://www.ferc.gov/industries/gas/enviro/guidelines/stakeholder-brochure.pdf.
- The Aspen Institute Dialogue on Energy Governance. "Stakeholder Engagement Best Practices and Recommendations." (2019). https://www.energy.gov/sites/default/files/2022-10/Infra_Topic_Paper_3-6_FINAL.pdf.
- IPIECA. "Community Grievance Mechanisms in the Oil and Gas Industry." January 2015. https://www.ipieca.org/resources/community-grievance-mechanisms-in-the-oil-and-gas-industry.
- Department of Energy, Office of Fossil Energy and Carbon Management. "Framework Engaging Communities, Stakeholders, and Tribes in Clean Energy Technologies." https://www.energy.gov/fecm/fossil-energy-and-carbon-management-domestic-engagement-framework-engaging-communities.
- Department of Energy, National Energy Technology Laboratory. (2017). "Best Practices for: Public Outreach and Education for Carbon Storage Projects (DOE/NETL/1845)."
- Bradbury, J., Greenberg, S., & Wade, S. (2011). "Communicating the Risks of CCS." Canberra, Australia. Global CCS Institute.
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- Forbes, S., Almendra, F., and Ziegler, M. (2010). "Guidelines for Community Engagement in Carbon Dioxide Capture, Transport, and Storage Projects." World Resources Institute, Washington DC.
- Health Effects Institute Energy (2022). "Guiding Principles for Research and Stakeholder Engagement." https://www.heienergy.org/sites/default/files/2022-04/heienergy-guiding-principles-2022.pdf.
- IPIECA. "Indigenous Peoples and the Oil and Gas Industry: Context, Issues and Emerging Good Practice." April 2012. https://www.ipieca.org.
- IPIECA. 2014. "Community Grievance Mechanisms Toolbox."
- United Nations. "Guiding Principles for Business and Human Rights." https://www.ohchr.org/sites/default/files/documents/publications/guidingprinciplesbusinesshr_en.pdf.

Appendix D-1

UNITS AND MEASUREMENTS

I. CONCENTRATION MEASUREMENTS BY SENSOR TYPE

1. **Point sensors** measure gas concentrations (e.g., mixing ratio of methane in atmosphere) at the sensor. Concentrations are typically expressed in ppmv (parts per million by volume, the number of molecules of methane per million molecules of the gas sample). Point sensors may be stationary or moving, and typically provide a time series of concentration measurements.
2. **Path-integrated sensors** produce gas concentration measured by the absorption of light over a long, typically open, path between the sensor and some type of reflective surface. Typical measurement units are ppm-m (parts per million* meter). When divided by the path length, the measurement in ppm-m gives the average mixing ratio (ppm) of methane.

   Path-integrated sensors may use reflected ambient light, active laser illumination, or active wide-spectrum illumination. For methane, these sensors operate in the mid- and short-wave infrared spectrum. Optical gas cameras, current satellite sensors, and many aerial imaging solutions utilize ambient light, typically sunlight, reflected from a background through a plume. Laser-based sensors may use a defined background (e.g., a retroreflector) or available background (e.g., the surface directly below an aircraft). For most sensors in active use, the light passes through the atmospheric emissions twice—once from the light source to reflective background, and again from reflective background to sensor. Note that path length is a function of the sensor position, ranging from a defined distance for a laser solution (i.e., to/from a reflective surface) to full atmospheric column for satellites.

II. EMISSIONS RATE ESTIMATES

Substantial calculation is often required to convert concentration *measurements* into *estimates* of the emissions rate at the time the concentration measurements were made. For example, a satellite instrument delivers a measurement of the atmospheric column concentration of methane. To convert these measurements to emissions rate estimates, algorithms must subtract off background methane concentrations, estimate transport from atmospheric conditions and meteorology, and apply computational algorithms to estimate emissions rate.[1, 2, 3]

The mass of methane emissions is described in numerous units. Standard mass units are

1 Thorpe, A.K., Frankenberg, C., Aubrey, A.D., Roberts, D.A., Nottrott, A., Rahn, T., Sauer, J.A., et al. 2016. "Mapping Methane Concentrations from a Controlled Release Experiment Using the Next Generation Airborne Visible/Infrared Imaging Spectrometer (AVIRIS-NG)." *Remote Sensing of Environment* 179 (June): 104–15. https://doi.org/10.1016/j.rse.2016.03.032.

2 Thorpe, A.K., Frankenberg, C., and Roberts, D.A. 2014. "Retrieval Techniques for Airborne Imaging of Methane Concentrations Using High Spatial and Moderate Spectral Resolution: Application to AVIRIS." *Atmospheric Measurement Techniques* 7 (2): 491–506. https://doi.org/10.5194/amt-7-491-2014.

3 Johnson, M.R., Tyner, D.R., Conley, S., Schwietzke, S., and Zavala-Araiza, D. 2017. "Comparisons of Airborne Measurements and Inventory Estimates of Methane Emissions in the Alberta Upstream Oil and Gas Sector." *Environmental Science & Technology* 51 (21): 13008–17. https://doi.org/10.1021/acs.est.7b03525.

often used: kilograms, pound-mass, and various definitions of ton (metric, short, etc.). Additionally, mass emissions may be described as volumetric emissions referenced to standard conditions, such as standard cubic feet, standard liters, or standard cubic meters. Volumetric expressions are only valid when standard conditions are provided, as numerous standard conditions are in active use, including 60°F/1 atm, 70°F/1 atm, 25°C/1 atm, or 0°C/1 atm.

In the United States, source-level emissions are often reported as volumetric units at standard conditions (i.e., a mass) of whole gas per unit time (e.g., standard cubic feet per hour). These data are useful for emissions inventories with the assumption that the total (standard) volume of gas measured to create the emissions factor is applicable to a wide range of gas compositions.

Emissions are rarely provided as volumetric results at the measurement conditions without converting to standard conditions (i.e., cubic feet rather than standard cubic feet). Any subsequent analysis must know, or assume, the measurement conditions to convert to a suitable mass unit. A fraction (%) of the lower explosive limit (e.g., % LEL) is an example of a volumetric result that is not in standard conditions.

Since results are delivered in a wide variety of units, data must be converted to a common basis to be compared or summed up. Standard mass units for a single chemical species can be directly summed. Additional conversion and/or care is required for volumetric units, even when reported at standard conditions, and for whole gas results.

Additionally, any of the above mass units can be expressed as an emissions rate, ranging from per second to per year. In general, most measurement or estimation methods provide one or more short-duration estimates of emissions rate at the time when the methane concentration was sensed. The time unit used in reporting the emissions rate does not imply the duration of the measurement. For example, emissions rates of kg/hr are frequently used to report an emissions measurement based on a few seconds of data.

Ultimately, the metric of most use is cumulative mass of methane emitted to the atmosphere over an extended period—i.e., emissions rate integrated over time. A common goal is an estimate of annual emissions. Therefore, a mass estimate of methane emissions requires accounting for temporal variability in the mass emissions rate of methane.

Appendix D-2

EMISSIONS DETECTION AND QUANTIFICATION TECHNOLOGIES

I. INTRODUCTION

This appendix summarizes the operation, sensing-system types and quantification methods for technologies in each of these categories:

1. Operator, handheld systems, deployed on-site
2. Fixed-ground monitors
3. Mobile-ground measurements
4. Drone-based measurements
5. Aircraft-based and high-altitude-based measurements
6. Satellite measurements

II. EMISSIONS DETECTION AND QUANTIFICATION TECHNOLOGIES

A. Operator, Handheld Systems, Deployed On-Site

Table D-1 lists handheld technology types commonly employed on-site. These techniques generally target individual sources, whether focused primarily or exclusively on detection, such as Audio, Visual, and Olfactory (AVO) and Optical Gas Imaging (OGI) surveys, or primarily used for quantification of emissions rates, such as high-flow sampling.

Measurement Platform	Measurement Type	Primary Segment and Use	Quantification Capabilities
Operator handheld; deployed on-site	AVO Detection	Upstream and downstream, often through public detection of odorants such as mercaptans in downstream natural gas	None
	OGI Camera	All segments	Qualitative
	Quantitative Optical Gas Imaging (qOGI) Camera	All segments, but widest reported uses are in upstream and midstream	Quantification, though with uncertainties that are not well established
	High-flow Sampling	Upstream and midstream	Based on instrument sampling rate and observed concentrations; upper bound constrained by sampling rate
	Method 21	Upstream and midstream	Based on correlation equations between sensed concentration of total hydrocarbons and independently measured emissions rates for a limited set of equipment
	Handheld Open-Path Laser	Upstream and downstream	Semiquantitative (integrated path-length concentrations, no emissions rates)

Table D-1. *Operator, Handheld Systems, Deployed On-Site*

1. Audio, Visual, and Olfactory (AVO) Inspection

In an AVO survey, an operator performs a walk-around of an operating site, using human senses of hearing, sight, and smell to detect potential emissions sources. "For certain leak sizes, a person can detect the sound of a leak, the smell of emitted gas, or other visual signals, such as darker deposits left on the equipment near a leak source where heavier condensing components in the gas stream drop out."[4] Experience with the normal sights and sounds of operations is implied, as a person would be using their senses to detect differences. Detection limits depend on the training and experience of the operator applying the method, as well as proximity of the observer to the emissions point and atmospheric conditions, such as wind speed. If a leak is detected, source localization is generally excellent and can be specified to a precise location. No quantification is possible with AVO, though it may be paired with other approaches that can quantify found emissions.

AVO methods are not as consistent as instrument detection methods, nor as sensitive as many handheld instrument methods. AVO is an important component of routine inspections, but there are limitations to using it as a sole method of identification. AVO methods are not as useful in high-noise environments, such as near compressors.

2. Optical Gas Imaging (OGI)

An OGI camera records absorption of infrared light to detect images of emissions plumes. Optical filters only allow wavelengths of infrared light absorbed by methane and other hydrocarbons to enter the camera. The camera creates color or black and white shade-coded images indicating where in the field of view methane and other hydrocarbons are absorbing infrared light. Emissions detection is based on operator interpretation of camera images; time series image analysis of the plumes can be performed to estimate emissions rates with additional tools or software.

Probability of detection and detection limits depend on distance from the source and other parameters. For example, detection limits of (median ±1σ) 3 ±0.8 g/hr, 6 ±0.8 g/hr, 20 ±0.8 g/hr for imaging distances of 1.5 m, 3m, and 6 m have been reported for experienced operators,[5, 6] although system performance improves with the experience of the operator.

Plume imagery allows for localization of the emissions source. The precision of localization depends on the distance from the source but is generally at the individual equipment level. An intercomparison of OGI and the Method 21 system (see Section II.A.5) at upstream oil and natural gas production sites found that many of the leaks that were identified only using Method 21 were on the lower end of the emissions rate distribution in the intercomparison. Conversely, OGI identified several components on the higher end of the study emissions rate distribution that were not identified with Method 21 approaches.[7]

If quantification of the detected emissions is needed, quantitative OGI may be used (see Section II.A.3). Alternatively, the sources may be analyzed using another type of device capable of quantification (e.g., the high-flow devices described in II.A.4) or emissions factors for leaks are applied based on component type and service (gas, light crude, heavy crude), which can then be used to estimate emissions rates. The most widely used set of emissions factors are those from the Environmental Protection Agency (EPA) Greenhouse Gas Reporting Program Part 98 Subpart W reporting requirements for petroleum and natural gas systems.

4 Interstate Technology & Regulatory Council. 2018. "Evaluation of Innovative Methane Detection Technologies." https://methane-1.itrcweb.org.

5 Ravikumar, Arvind P., and Adam R. Brandt. 2017. "Designing Better Methane Mitigation Policies: The Challenge of Distributed Small Sources in the Natural Gas Sector." *Environmental Research Letters* 12 (4): 044023. https://doi.org/10.1088/1748-9326/aa6791.

6 Ravikumar, A.P., Wang, J., McGuire, M., Bell, C.S., Zimmerle, D., and Brandt, A.R. 2018. "Good versus good enough? Empirical Tests of Methane Leak Detection Sensitivity of a Commercial Infrared Camera." *Environmental Science & Technology* 52, no. 4: 2368-2374. https://pubs.acs.org/doi/10.1021/acs.est.7b04945.

7 Pacsi, A.P., Ferrara, T., Schwan, K., Tupper, P., Lev-On, M., Smith, R., and Ritter, K. 2019. "Equipment Leak Detection and Quantification at 67 Oil and Gas Sites in the Western United States." *Elementa: Science of the Anthropocene* 7; 29. https://doi.org/10.1525/elementa.368.

3. Quantitative Optical Gas Imaging (qOGI)

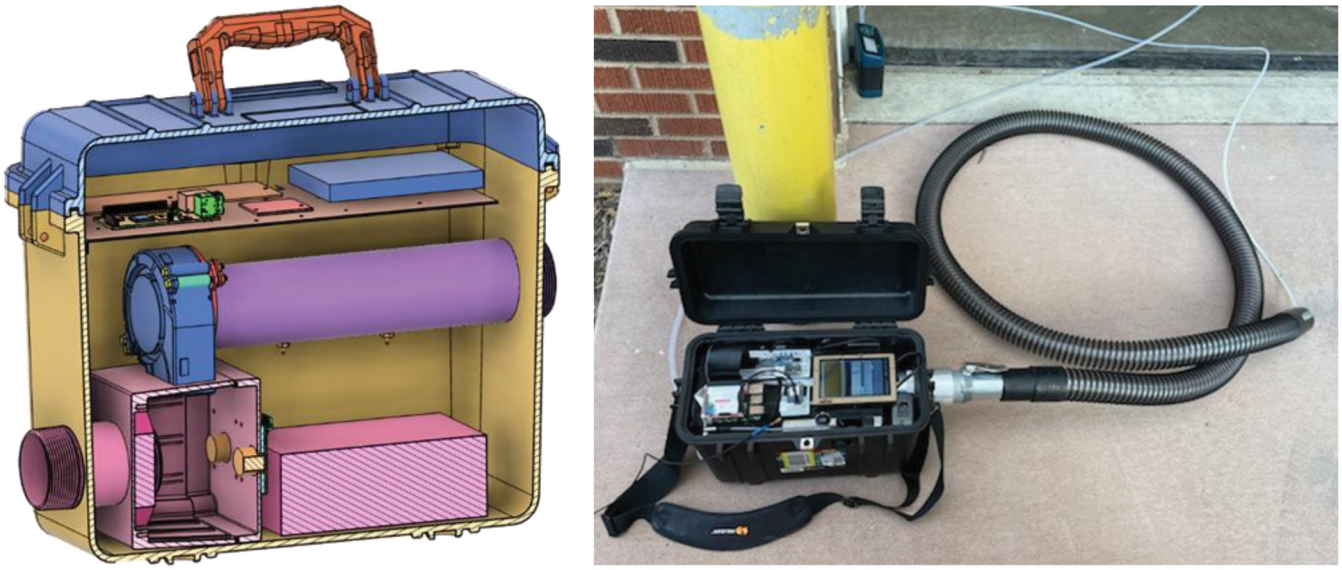
Some OGI cameras (multiple vendors, e.g., https://www.concawe.eu/wp-content/uploads/2017/01/rpt_17-2.pdf) can be fitted with tablets that use proprietary plume imagery analysis techniques for quantification of the emissions source. Limited data are available on the effectiveness of quantification algorithms, and the algorithms continue to evolve.

4. High-Flow Sampling

High-flow sampling systems actively and continuously draw in a metered air sample from an emissions point. The emissions rate is determined by multiplying the metered flow rate by a concentration of methane in the sampled gas. There are multiple configurations of high-flow measurements using different methods of drawing in sample with a range of maximum flow rates and different composition measurement systems. High-flow sampling systems are generally used for sources with relatively low emissions rates, since the maximum emissions rate that can be sampled quantitatively is limited by the maximum flow rate that can be drawn into the instrument. Some high-flow instrument configurations enclose the emissions source, and the instruments draw air in from the enclosure. If an enclosure is not used, an ambient air sample is drawn into the instrument from the vicinity of the point of emission. In this case, the maximum emissions rate that can be sampled by the instrument is generally significantly lower than the maximum flow rate drawn into the instrument. The most commonly used commercial high-flow instrument, the Bacharach® HI FLOW® Sampler is no longer manufactured. An open-source architecture for future high-flow instruments has been developed and a conceptual diagram of the design and a photograph of a prototype are provided in Figure D-1.[8]

Detection limits are determined by a combination of sensor detection limits and the range of flow rates that can be achieved by the blower. Detection limits as low as 0.15 standard liters per minute (6 g/hr) are achievable. The National Physical Laboratory in the United Kingdom evaluated the Bacharach® HI FLOW® Sampler and concluded that the "sampler [is] suitable for measuring methane emissions if operated within its

8 Zimmerle, D., Vaughn, T., Bennett, K., Ross, C., Harrison, M., Wilson, A., and Johnson, C. 2022. "Open-Source High Flow Sampler for Natural Gas Leak Quantification, Final Report." Prepared for the California Air Resources Board. April 14, 2022. https://ww2.arb.ca.gov/sites/default/files/2022-06/High_Flow_Final_Report_ada.pdf.



Source: Zimmerle et al., 2022.

Figure D-1. *Conceptual Diagram of the Open-Source Design for a High-Flow Sampler and Photograph of a Prototype Instrument*

limitations."[9] Field testing at the Methane Emissions Technology Evaluation Center (METEC) at Colorado State University suggests that, in the field, a high-flow instrument, or similar instrument of any design, underestimates emissions. The underestimate is due, in part, to the challenge of capturing all emissions from a source,[10] and the testing team advised characterizing uncertainties and establishing best practices for instrument deployment.

5. Method 21

Method 21 was developed to detect volatile organic compound leaks from process equipment, including valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, and vessel vents.[11] A portable instrument, such as the device shown in Figure D-2, is used to actively draw in air from an emissions point and detect and measure the concentration of hydrocarbons in the sampled air. A variety of detector types can be used to detect hydrocarbons and include, but are not limited to, catalytic oxidation, flame ionization, infrared absorption, and photoionization. An electrically driven pump provides air flow to the detector at a constant flow rate. The air flow into the instrument is generally in the range of 0.10 l/min to 3.0 l/min (0.004 ft^3/min to 0.1 ft^3/min). In its description of the method, EPA states that "this method is intended to locate and classify leaks only and is not to be used as a direct measure of mass emissions rate from individual sources."[12]

Source: Thermo Fisher Scientific.

Figure D-2. *Representative Device That Meets the Requirements of Method 21, Thermo Scientific TVA Handheld Open-Path Laser*

Leaks are detected by placing the inlet of the device at the surface of the component where leakage could occur and moving the probe to identify the maximum concentration indicated by the hydrocarbon analyzer. A typical threshold for defining a leak among oil and natural gas infrastructure is a maximum observed concentration of 500 ppm (based on a calibration of the instrument for methane when methane emissions are the target), although other thresholds can be used.[13]

If emissions quantification of the detected emissions is needed, the sources may be subsequently analyzed using a device capable of quantification (e.g., the high-flow devices described in II.A.4) or emissions correlation equations can be used to estimate emissions rates of whole gas flow based on component type. Currently, EPA reporting includes options for emissions estimation based on emissions factors for leaks that are conceptually similar to those in the OGI section.

9 Connolly, J.I., Robinson, R.A., and Gardiner, T.D. 2019. "Assessment of the Bacharach Hi Flow® Sampler Characteristics and Potential Failure Modes When Measuring Methane Emissions." *Measurement* 145 (October): 226–33. https://doi.org/10.1016/j.measurement.2019.05.055.

10 Zimmerle, D., Vaughn, T., Bennett, K., Ross, C., Harrison, M., Wilson, A., and Johnson, C. 2022. "Open-Source High Flow Sampler for Natural Gas Leak Quantification, Final Report." Prepared for the California Air Resources Board. April 14, 2022. https://ww2.arb.ca.gov/sites/default/files/2022-06/High_Flow_Final_Report_ada.pdf.

11 EPA. 2017. "Title 40, Protection of the Environment, Method 21." *Code of Federal Regulations.* https://www.epa.gov/sites/default/files/2017-08/documents/method_21.pdf.

12 EPA. 2017."Title 40, Protection of the Environment, Method 21." *Code of Federal Regulations.* https://www.epa.gov/sites/default/files/2017-08/documents/method_21.pdf.

13 Pacsi, A.P., Ferrara, T., Schwan, K., Tupper, P., Lev-On, M., Smith, R., and Ritter, K. 2019. "Equipment Leak Detection and Quantification at 67 Oil and Gas Sites in the Western United States." *Elementa: Science of the Anthropocene* 7; 29. https://doi.org/10.1525/elementa.368.

Handheld devices with open-path laser systems have been deployed in walking-based surveys. The most applied system integrates a tunable diode laser system into a handheld device, which detects methane over an integrated path length in units of parts per million* meters (ppm-m). Leak detection is defined using threshold detection and analogous thresholds used in Method 21.

B. Fixed-Ground Monitors

Table D-2 lists commonly employed fixed-ground monitoring technology types. These include fixed-point and open-path approaches that provide both detection and quantification.

1. Fixed-Point Measurement Systems

Fixed-point sensing systems placed on oil and natural gas sites are typically self-powered, have independent data communication systems, and continuously collect meteorological and methane concentration data. In a typical deployment, one to six or more systems may be deployed at a single site, to be able to detect emissions from all emissions sources at a facility. When an elevated concentration of methane is detected, local wind speed and wind direction data are used to identify the emissions source. Once the source location is identified, atmospheric dispersion models are used to convert the observed concentration into an estimated emissions rate. A deployment configuration is shown conceptually in Figure D-3.

The fixed-point measurement system consists of one or more individual point monitoring systems. Each system includes a sensor, a power source, a communications capability that allows frequent data downloads, a data analytics system, and often, a dedicated meteorological station. Fixed-point measurement systems based on different types of sensors have been deployed, including metal oxide, catalytic oxidation, nondispersive infrared, photo ionization detectors, flame ionization detectors, or cavity ring-down spectrometers. An individual measurement system typically only incorporates one of those sensor types. The data analytics systems convert the sensor signal (electric current, spectrometer signal, etc.) into an estimated concentration, approximate the location of the source of the emissions based on wind field data, and estimate emissions rates based on assumed source location and atmospheric dispersion modeling. The accuracy of the emissions rate quantification is dependent on the performance of the sensor, the geolocation systems, and the dispersion modeling. In principle, sensors can detect concentration enhancements associated with relatively low emissions rates, but the uncertainties associated with proper geolocation of the source and the dispersion modeling are significant.[14]

14 Bell, A., and Yuan, S. 2023. "Performance of Continuous Emission Monitoring Solutions under a Single-Blind Controlled Testing Protocol." *Environmental Science and Technology* 57, 14, 5794-5805. https://doi.org/10.1021/acs.est.2c09235.

Measurement Platform	Measurement Type	Primary Segment and Use	Quantification Capabilities
Fixed ground	Fixed-point measurement of concentration	Upstream and midstream operations	Based on dispersion modeling, statistical pattern matching, or machine learning
	Path-integrated concentration	Upstream and midstream	Based on dispersion modeling; systems that measure paths at multiple heights may obtain whole-site emissions rates using mass balance methods
	Remotely operated OGI Camera	Upstream and midstream	Semiquantitative; image processing may allow for quantification
	Micro-Electro-Mechanical Systems (MEMS)	Upstream (emergent)—tank emissions detection	Unknown

Table D-2. *Fixed-Ground Monitoring Systems*

Source: D. Zimmerle, Colorado State University.

Figure D-3. *Using Fixed-Point Sensors (Black Poles) to Measure Concentrations in or near the Emissions Plume from a Facility*

2. Path-Integrated Measurement Systems

Open-path ground measurement systems use a laser source to transmit a collimated open-path beam to a remote reflector or reflectors. The reflected beam is detected and the absorption of methane along the path length is determined. With favorable wind directions, the sensor beam can sense a portion of an emissions plume. A deployment configuration is shown conceptually in Figure D-4.

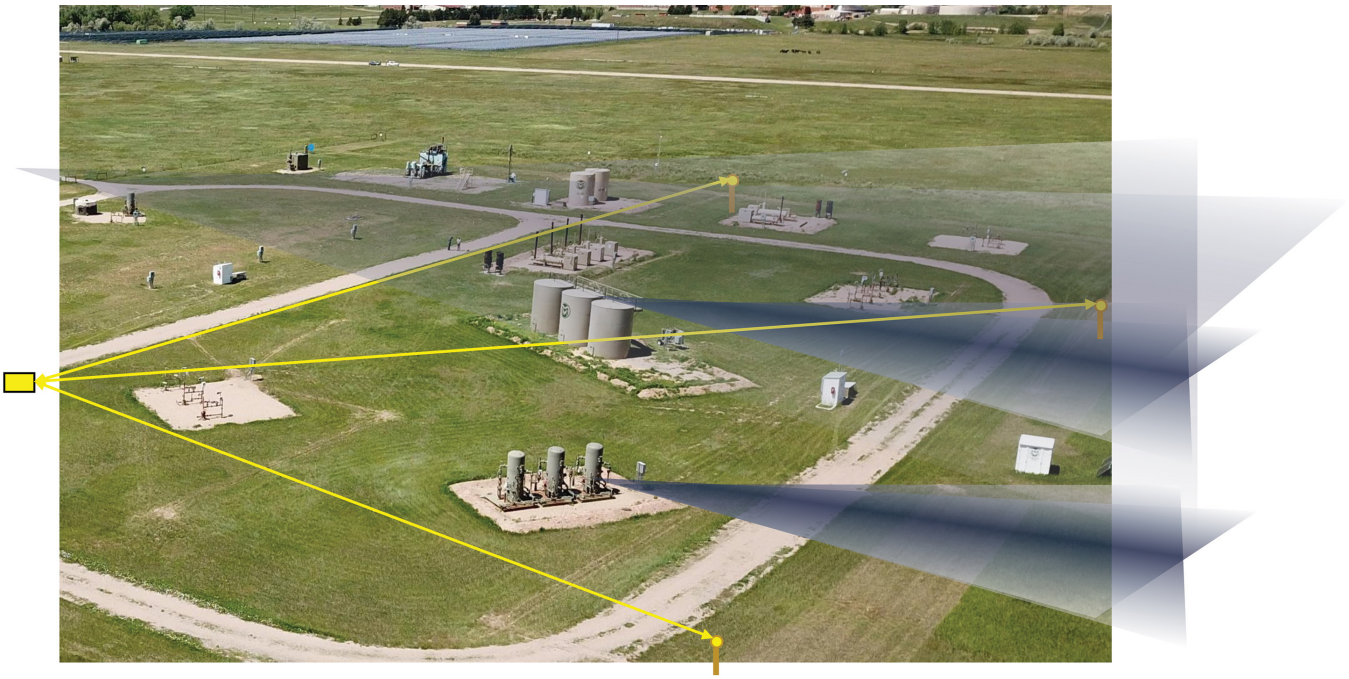
Absorption along the path length is used to calculate a path average concentration, typically in units of ppm-m. When combined with meteorological data (wind direction and speed), these systems can model and estimate the rate of emissions. Source locations are estimated using wind direction and speed data combined with knowledge of equipment locations on the monitored sites. Emissions rates are calculated by an empirical relationship developed using gas transport modeling related to the detected concentration path length.

Open-path systems with relatively short path lengths have been deployed on single sites. Longer path length systems, with path lengths of several kilometers, can cover multiple upstream sites. Reports of single-blind tests of long path-length systems, performed at the METEC, state that "the system detects 100% of leaks, including leaks as small as 0.96 g min^{-1} (3.1 scfh)." It attributes leaks to the correct pad or equipment group (tank battery, separator battery, wellhead battery) 100% of the time and to the correct equipment (specific separator, tank, or wellhead) 67% of the time. All leaks are quantified to within 3.7 g min^{-1} (12 scfh); 94% are quantified to within 2.8 g min^{-1} (9 scfh)."[15]

3. Optical Gas Imaging (OGI)

One or more OGI cameras, like those described in II.A.2, can be permanently affixed to a tall pole and directed at a facility area of interest (such as tanks, compressors, or flares) or mounted on a gimbal that rotates between multiple facility areas of interest.

15 Alden, C.B., Coburn, S.C., Wright, R.J., Baumann, E., Cossel, K., Perez, E., Hoenig, E., et al. 2019. "Single-Blind Quantification of Natural Gas Leaks from 1 km Distance Using Frequency Combs." *Environmental Science & Technology* 53 (5): 2908–17. https://doi.org/10.1021/acs.est.8b06259.



Notes: Yellow poles represent reflectors. Yellow square represents sensors. Yellow lines represent paths.

Source: D. Zimmerle, Colorado State University.

Figure D-4. *Using Fixed, Open-Path Sensors to Measure Concentrations along Paths That Can Intersect Emissions Plumes from a Facility*

4. Micro-Electro-Mechanical Systems (MEMS)

MEMS systems are a relatively recent entrant to the technology ecosystem. The system uses an array of low-cost sensors, interconnected as a mesh network of sensors, that are mounted near potential leak sources, such as on tanks near thief hatches or other sources. The mesh network is connected to data and analytics systems, which enable rapid detection and localization (https://nevadanano.com/mps-methane-gas-sensor/#application).

C. Mobile-Ground Measurements

Table D-3 lists commonly employed mobile-ground monitoring technology types. These include vehicle-mounted instrumentation deployed downwind of sites with active searching for emissions plumes, which may or may not have tracer releases on-site. Vehicle-mounted systems are also used extensively in finding leaks from distribution systems, interpretation of these data is more difficult than for deployments where emissions are known to be above ground.

1. Vehicle-Mounted Instrumentation, with and without Tracer Release

In these systems, an automobile or van is used as a mobile detection system by mounting a methane sensor that is either external to the vehicle, or a system that draws air into a sensor that is inside the vehicle. The vehicle measures the concentration of methane in air at the location of the vehicle. This type of system can be deployed using several methodologies:

- An encirclement of the site and source by the vehicle (using EPA Other Test Method 33A)[16]
- Downwind tracer gas analysis, where a tracer gas is released on-site, and the mobile vehicle system drives downwind transects through the plume, detecting both methane and the tracer gas

16 Brantley, H., Thoma, E., Squier, W., Guven, B., and Lyon, D. 2014. "Assessment of Methane Emissions from Oil and Gas Production Pads Using Mobile Measurements." *Environmental Science & Technology* 48 (24): 14508–15. https://doi.org/10.1021/es503070q.

Measurement Platform	Measurement Type	Primary Segment and Use	Quantification Capabilities
Mobile ground	Vehicle-mounted instrumentation with tracer release on-site	Upstream and midstream; research activities	Either based on dispersion modeling or on tracer release near source
	Vehicle mounted sensor without tracer (EPA OTM 33A)	Upstream, distribution; research activities	Based on dispersion modeling for sites with well-defined plumes
	Vehicle with Solar Occultation Flux detection	Upstream	Samples entire cross section of plume; emissions determined based on plume modeling
	Dedicated survey vehicles	Distribution and pipeline systems	Based on dispersion models or statistical matching. Dispersion-based quantification is difficult due to complexity of dispersion

Table D-3. *Mobile-Ground Monitoring Systems*

For vehicle-based approaches without tracer releases, data are gathered in two steps. Data are initially collected by driving through/around a facility using a high-speed, high-accuracy methane sensing system to identify enhancements in the concentration of methane. Once a plume is identified, the analyzer is located either as close as possible to the center of the plume (for up to ~20 minutes of stationary data collection), or transects are driven through the plume.

Either Gaussian or Lagrangian approaches to modeling plume dispersion are used for emissions quantification. Using a Gaussian plume model typically requires good characterization of micrometeorology to obtain reliable estimates of plume dispersion. This is particularly challenging in areas with obstructions to the air flow, and several assumptions may need to be built into the modeling, for example, surface roughness and stability of air.

A backward Lagrangian stochastic model (e.g., WindTrax)[17] can also be used to characterize plume dispersion and estimate emissions from downwind concentration measurements. This model is not constrained by the shape or size of the source, and it can model emissions from point sources, line sources, or area sources. However, it relies on an idealized calculation of atmospheric dispersion and can result in inaccurate emissions under light wind conditions and both extremely stable and unstable stratification.[18]

Rather than using atmospheric modeling, some implementations of vehicle-based measurements use a tracer release.[19] The tracer system uses a principle of assumed equal dispersion of the target species and an intentionally released tracer gas species. Common tracer species include acetylene, nitrous oxide (N_2O), and, historically, sulfur hexafluoride (SF_6). Sulfur hexafluoride is less commonly used in current deployments, at least in part because of its high greenhouse gas (GHG) Global Warming Potential (GWP100 of 23,500).[20] Tracer species are selected that have very low background concentrations in the

17 Crenna, Brian. 2006. "An Introduction to WindTrax." Accessed April 16, 2024. http://www.thunderbeachscientific.com/downloads/introduction.pdf.

18 Gao, Z., Desjardins, R.L., van Haarlem, R.P., and Flesch, T.K. 2008. "Estimating Gas Emissions from Multiple Sources Using a Backward Lagrangian Stochastic Model." *Journal of the Air & Waste Management Association* 58 (11): 1415–21. https://doi.org/10.3155/1047-3289.58.11.1415.

19 Roscioli, J.R., Yacovitch, T.I., Floerchinger, C., Mitchell, A.L., Tkacik, D.S., Subramanian, R., Martinez, D.M., et al. 2015. "Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Methods." *Atmospheric Measurement Techniques* 8 (5): 2017–35. https://doi.org/10.5194/amt-8-2017-2015.

20 Ward, M., Tulloch, A.I.T., Radford, J.Q., Williams, B.A., Reside, A.E., Macdonald, S.L., Mayfield, H.J., et al., 2020. "Impact of 2019–2020 Mega-Fires on Australian Fauna Habitat." *Nature Ecology & Evolution* 4 (July): 1–6. https://doi.org/10.1038/s41559-020-1251-1.

atmosphere so that they can be detected at very low concentrations by some of the same sensing systems as used for methane. The tracer is released at a known rate. The ratio of the methane to the tracer species in downwind air is multiplied by the tracer release rate to estimate the methane emissions rate. This method requires mobile access perpendicular to the wind direction between 200 m and 1,500 m downwind from the site, such that the sensor can be moved across the plume, and measurement equipment capable of measuring methane and a tracer gas or gases. Dual tracers can be placed on the site and the shapes of the tracer and source plumes can be used to increase confidence that the targeted source is being measured. A typical configuration is shown in Roscioli et al (2015).[21] In this case, the two tracers are N_2O (nitrous oxide) and C_2H_2 (acetylene) and the tracers are located adjacent to two potential sources of methane. A methane plume is shown adjacent to the acetylene release and no methane plume is shown adjacent to the nitrous oxide release. Depending on the downwind distance of the vehicle transecting the plumes, the plumes may either all be detected at the same locations (farther downwind distance), or the relative positions of the plumes may be used to identify the location of the plume (nearer downwind distance).

In general, the tracer approach leads to much lower uncertainties in estimating emissions rates than approaches that require atmospheric dispersion modeling. Allen et al.,[22] have investigated the dependence of the accuracy of the emissions estimate on the proximity of the tracer release to the source for oil and natural gas production sites.

2. Solar Occultation Flux

In the Solar Occultation Flux (SOF) method, the absorption spectra of a plume are measured using the sun as the infrared source with a broadband detector (spectrometer) mounted in a vehicle. A typical configuration is shown conceptually in Figure D-5.

If the vehicle transits through or below a plume, the infrared absorption detected by the spectrometer in the vehicle samples an entire cross section as the vehicle drives a transect through the plume. Figure D-6 shows a typical drive pattern and mapping of total atmospheric column concentration above the vehicle.

To quantify emissions, wind measurements must also be made, which, along with the measured column concentration, are used to calculate the emissions rate. Current SOF instruments have difficulty resolving methane and have been more broadly deployed for volatile organic compounds.

3. Dedicated Vehicle-Based Emissions Detection for Distribution and Pipeline Systems

A vehicle is equipped with a spectrometer that detects methane at parts per billion concentrations. A sampling system, likely a ¼-inch tubing gas inlet mounted approximately 12 inches to 18 inches above the ground level outside of the car with a pump to draw air into the spectrometer. The vehicle is typically also equipped with meteorological data collection equipment for wind speed, direction, humidity, and temperature, etc.

Concentrations of methane are mapped over the path of the vehicle and analytics systems are applied to estimate emissions rates associated with observed enhancements of methane above background.

D. Drone-Based Measurements

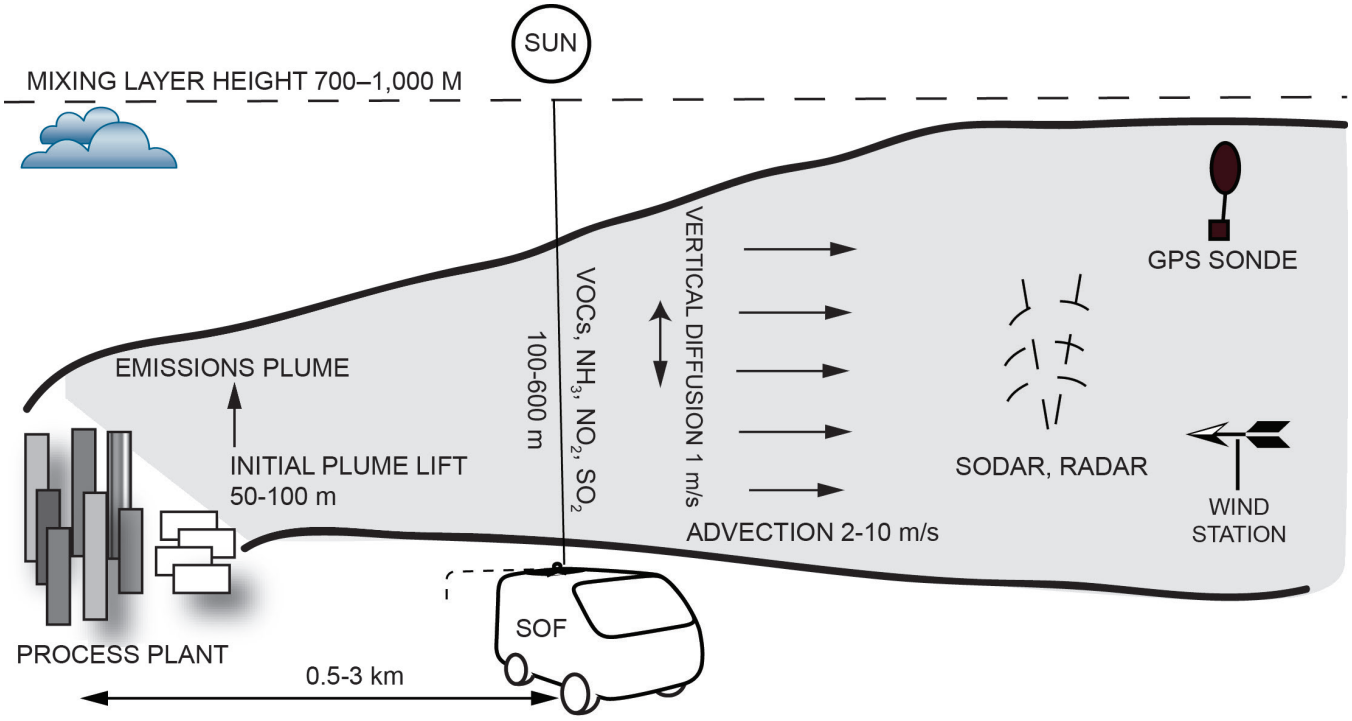
Table D-4 lists commonly employed drone-based technologies.

1. Drone-Based Mass Flux

Drone-based approaches, analogous to ground vehicle approaches, are based on the ability to sample upwind or upwind and downwind of a site.

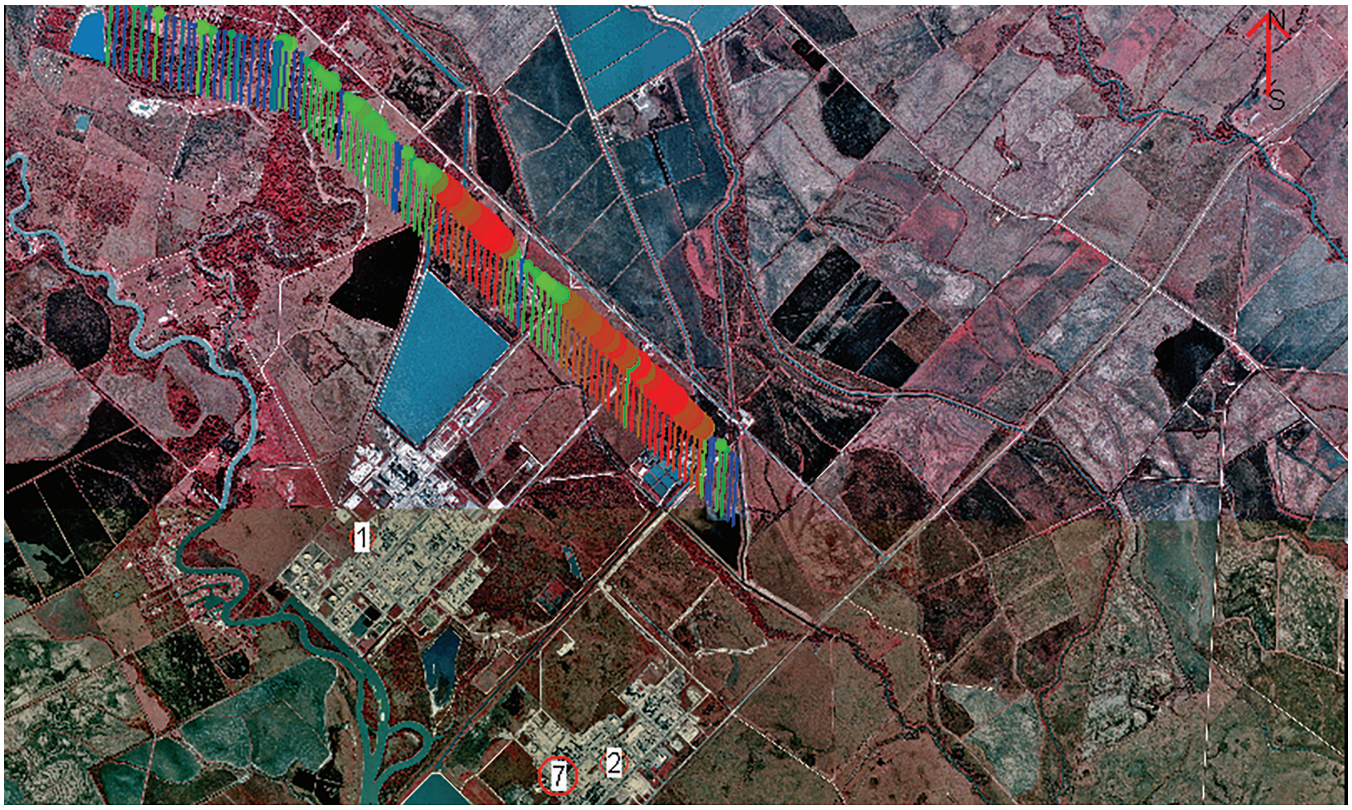
21 Roscioli, J.R., Yacovitch, T.I., Floerchinger, C., Mitchell, A.L., Tkacik, D.S., Subramanian, R., Martinez, D.M., et al. 2015. "Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Methods." *Atmospheric Measurement Techniques* 8 (5): 2017–35. https://doi.org/10.5194/amt-8-2017-2015.

22 Allen, D., Torres, V., Thomas, J., Sullivan, D., Harrison, M., Hendler, A., Herndon, S., et al. 2013. "Measurements of Methane Emissions at Natural Gas Production Sites in the United States." *Proceedings of the National Academy of Sciences* 110 (44): 17768–73. https://doi.org/10.1073/pnas.1304880110.



Source: Mellqvist, J., et al., 2007.

Figure D-5. *Solar Occultation Flux Method*



Source: Mellqvist, J., et al., 2007.

Figure D-6. *Typical Drive Pattern and Mapping of Total Atmospheric Column Concentration above the SOF Vehicle, Downwind of an Industrial Source*

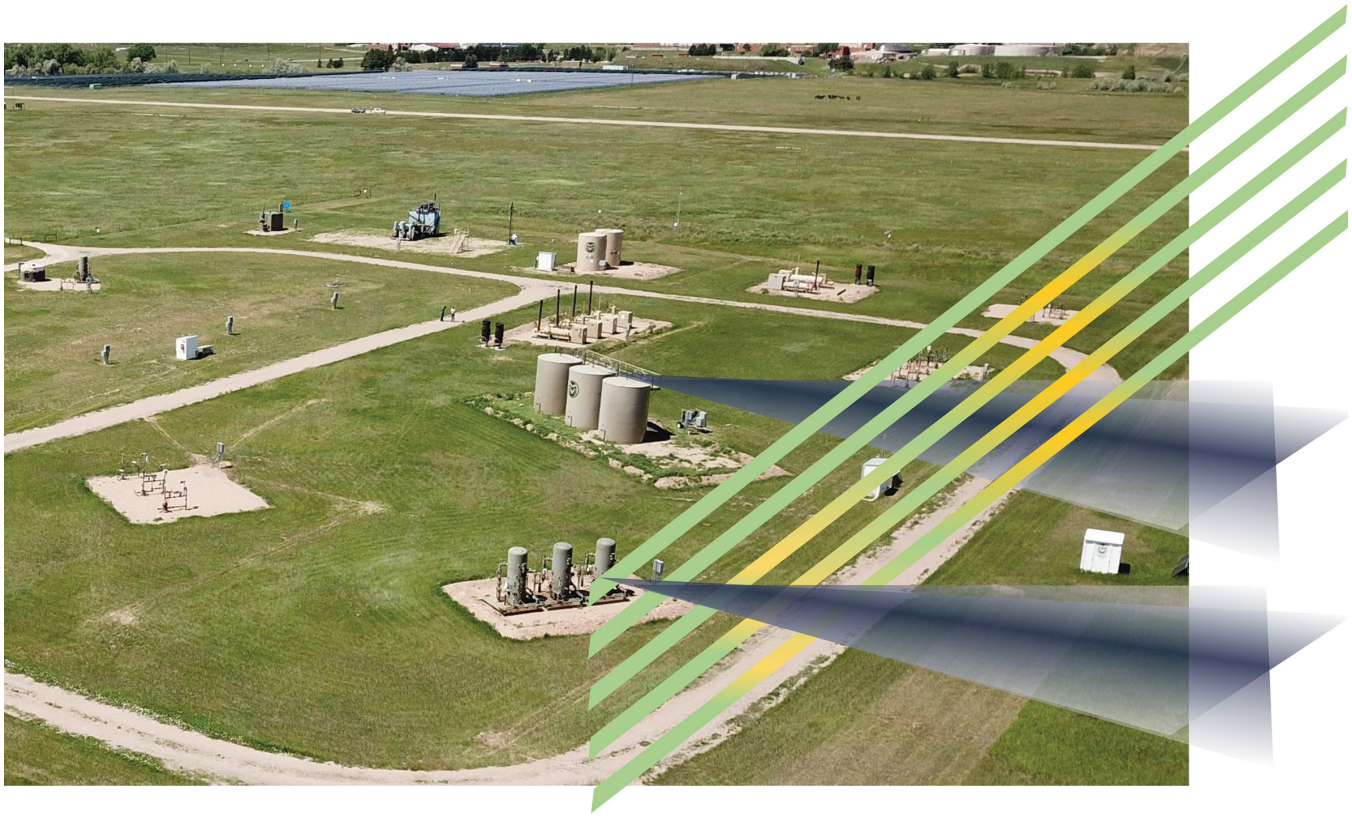
Measurement Platform	Measurement Type	Primary Segment and Use	Quantification Capabilities
On-site rotary UAV	On-board sensor; with pilot; mass balance flux curtain	Upstream and midstream	Based on mass balance (a.k.a. flux plane) methods

Table D-4. *Drone-Based Monitoring Systems*

The advantage of drone-based systems is their ability to sample at multiple elevations, rather than exclusively at ground level. A typical vertical raster flight path downwind of a plume is shown in Figure D-7.

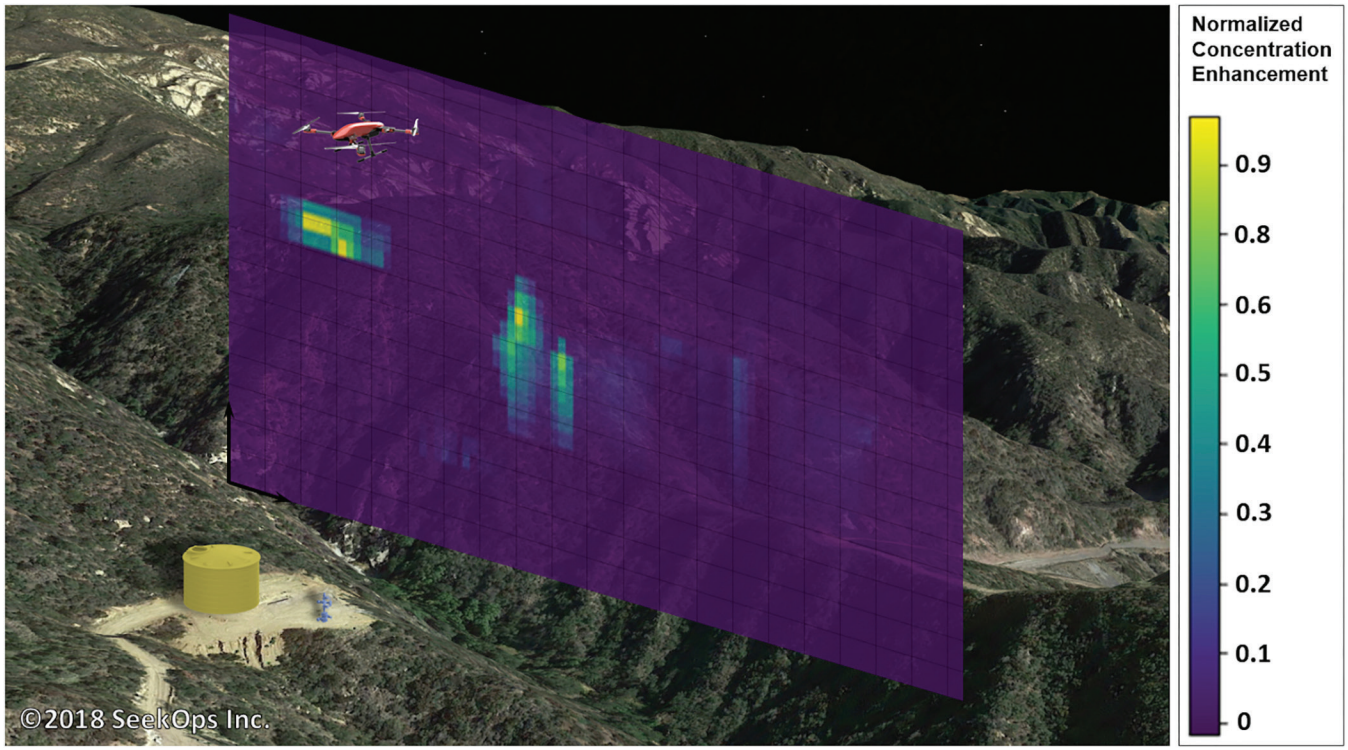
A laser contained within a porous housing provides the light source for absorption spectroscopy, so while the laser path is open to the atmosphere, and the device is commonly referred to as open path, the sensor is a point sensor. The instrument is typically sensitive (~10 ppb), lightweight (allowing drone mounting), and fast (<0.5 seconds). The method both detects and quantifies emissions.

In a typical deployment, a drone is flown initially in detection mode, locating emissions sources, followed by a quantification mode in which the drone flies vertical raster patterns, similar to that shown in Figure D-7. The drone measures methane concentration, height above ground, and GPS location. These data are combined with wind speed and direction data from a portable local weather station to calculate the mass of methane transported through the vertical raster. Figure D-8 illustrates a flux plane downwind of a source. Methane concentration enhancements, relative to a background in a continuous grid, are combined with wind speed and direction to calculate an emissions rate. For a



Source: D. Zimmerle, Colorado State University.

Figure D-7. *Vertical Raster Drone Flight Pattern for Emissions Rate Quantification*



Source: Corbett and Smith, 2022.

Figure D-8. *Flux Plane of Methane Downwind of a Source*

commonly deployed drone system, testing using controlled releases in a flow rate range of 0 kg/hr–15 kg/hr had an average accuracy of ±16%.[23] Emissions detection limits can be <1 scf/hr, but depend on downwind measurement distance and wind conditions. Shaw et al.,[24] provide a review of drone-based methods for methane emissions quantification.

E. Aircraft-Based and High-Altitude-Based Measurements

Table D-5 lists the commonly employed aircraft-based systems. Table D-6 lists high-altitude platform systems.

1. Aircraft-Based Mass Flux

One type of aircraft-based measurement is commonly referred to as a mass balance measurement. The objective of a mass balance method is to spatially characterize the incoming and outgoing concentration of methane in a target area. Spatially resolved concentrations along a flight path upwind and downwind of the area can then be combined with wind data to compute the transport of the target gas into and out of the area.

A common flight pattern has the plane upwind and downwind of a facility or a region, building up a concentration map between the ground and the aircraft from as close to ground level as possible to above the plume height. This vertical raster flight pattern can be flown much closer to ground level with a drone than with a fixed-wing aircraft. In a second common flight pattern, the aircraft flies in a spiral pattern around a facility to measure concentrations both upwind and downwind, from as close to ground level as possible to above plume height. This flight pattern is often termed spiral flight.

23 Corbett, Abigail, and Brendan Smith. 2022. "A Study of a Miniature TDLAS System On-Board Two Unmanned Aircraft to Independently Quantify Methane Emissions from Oil and Natural Gas Production Assets and Other Industrial Emitters." *Atmosphere* 13 (5): 804. https://doi.org/10.3390/atmosl3050804.

24 Shaw, J.T., Shah, A., Yong, H., and Allen, G. 2021. "Methods for Quantifying Methane Emissions Using Unmanned Aerial Vehicles: A Review." *Philosophical Transactions of the Royal Society A: Mathematical, Physical and Engineering Sciences* 379 (2210): 20200450. https://doi.org/10.1098/rsta.2020.0450.

Measurement Platform	Measurement Type	Primary Segment and Use	Quantification Capabilities
Aircraft and fixed-wing drone	On-board instrument measuring along flight path	Upstream, midstream, and downstream	Mass balance spirals or boxes or transects
	LiDAR and hyperspectral imaging	Upstream, midstream, and downstream	Mass balance based on plume mapping
High-altitude stratospheric balloon	Hyperspectral imaging, on-board instrument measuring along flight path	Basin-level coverage for extended periods (weeks)	Mass balance based on plume mapping

Table D-5. *Aircraft-Based Systems*

For fixed-wing aircraft, there is appreciable risk that some portion of the emissions may pass below the lowest aircraft flight line; typically, concentrations measured in lower flight lines are extrapolated to ground level using some assumptions.

2. LiDAR and Hyperspectral Imaging

Another type of aircraft-based system has sensors that create a map of path-integrated concentration between the flight altitude of the aircraft and the ground/equipment below. Three sensor types are in common use: (a) 2D hyperspectral or single-band cameras, (b) sweeping single-pixel sensors that create at 2D image, and (c) Light detection and ranging (LiDAR) sensors that sweep a laser across the scene below and create a 2D image of path-integrated emissions concentration. Sensors (a) and (b) use ambient light, sensor (c) uses the laser as the light source. Sensors may be multiband (hyperspectral cameras) or single-band (LiDAR, single-band cameras).

Flight speeds are typically hundreds of kilometers per hour for manned, fixed-wing aircraft. Flight altitudes vary from several hundred to 3,000 meters. Solutions can be deployed for both facilities and pipelines. Resolution depends on sensor type, flight altitude, angle-of-view, and flight speed. Sensor packages include extensive electronics for operating the sensor elements and controlling the motion of the aircraft; degree of control varies by solution. Field of view ranges from meters to approximately five kilometers to either side of the flight path. Many solutions also include a camera to provide visual imagery that is spatially aligned with the sensor camera.

Emissions quantification requires meteorological data and proceeds through a series of steps. First, any enhancement of methane emissions concentration is identified. Detection methods typically identify enhancements by localizing groups of pixels with concentrations significantly higher than surrounding pixels; details vary by solution developer. Second, once an enhancement is detected, pixels must be classified as those inside and those outside the plume. Pixels inside the plume are converted to concentration enhancements by subtracting an estimate of background concentrations, typically from areas outside the plume. This generally results in a color-coded heat map of concentration pixels. Finally, analytics are used to estimate the emitter location and the emissions rate. Emissions location is estimated by analyzing the shape of the detected plume to determine its likely origin. Methods vary in sophistication, including simple methods such as selecting the most upwind pixels or the highest concentration pixels as the origin; machine learning and statistical matches to known plumes have also been used. Emissions rate is calculated by summing the mass of

Measurement Platform	Measurement Type	Primary Segment and Use	Quantification Capabilities
High-Altitude Platform Systems	Hyperspectral imaging	Upstream and midstream	Mass balance based on plume mapping

Table D-6. *High-Altitude Platform Systems*

Measurement Platform	Measurement Type	Primary Segment and Use	Quantification Capabilities
Satellite	Area mappers	Global coverage of basin-level measurements with high frequency	Current grid resolution is ~50 km^2 with >1,000 kg/hr threshold
	Point measurements	Targeted point sources	Typical reported thresholds of 500 kg/hr-1,000 kg/hr for current instruments with lower thresholds anticipated for instruments scheduled for 2024 and later

Table D-7. Satellite Systems

emissions inside the plume and multiplying that by the transport speed from the meteorological data; specifics vary between individual solutions and are often considered proprietary.

3. High-Altitude Stratospheric Balloon

High-Altitude Platform Systems (HAPS) consist of balloons filled with helium that rise to, and fly within, the stratosphere. These balloons can carry payloads such as hyperspectral sensors, which can be used for remote sensing detection and quantification of methane emissions.

HAPS do not have propulsion systems. To stay in a region of interest (station keeping) HAPS systems move up and down in the stratosphere to catch wind currents with desired directions. HAPS can move up and down by compressing air to a ballast or releasing air from the ballast, which changes the balloon's density relative to the atmosphere.[25] Bellemare et al.,[26] evaluated station-keeping capabilities of HAPS balloons using simulations, by counting the time that the system would be within a domain with a radius of 50 km, and found that ~40%-70% of the time the HAPS would be inside the area of interest. Because HAPS systems rely on wind currents in the stratosphere for station keeping, operation may be limited to particular times of the year. Bellemare et al.,[27] reported a flight with a HAPS system that lasted 39 days.

Methane detection and quantification technology is similar to aircraft or satellite technologies using hyperspectral imaging. The enhancement of concentrations is first identified, then there is masking of the plume, and, finally, analytics, to quantify the emissions rate. Detection thresholds need to be characterized; however, they are expected to be intermediate between airplane and satellites detection limits. Recent tests suggest HAPS-based systems can detect emissions as low as 10 kg/hr.

F. Satellite Measurements

Table D-7 lists satellite measurement systems.

Satellite-based measurements are a rapidly expanding set of technologies for methane emissions detection and quantification with a large spatial coverage and frequent repeat measurements. A review of satellite missions with the potential for methane emissions monitoring is provided by Jacob et al., (2022).[28] Satellites detecting and

25 Bellemare, M.G., Candido, S., Castro, P.S., Gong, J. Machado, M.C., Moitra, S., Ponda, S.S., et al. 2020. "Autonomous Navigation of Stratospheric Balloons Using Reinforcement Learning." *Nature* 588 (7836): 77–82. https://doi.org/10.1038/s41586-020-2939-8.

26 Bellemare, M.G., Candido, S., Castro, P.S., Gong, J. Machado, M.C., Moitra, S., Ponda, S.S., et al. 2020. "Autonomous Navigation of Stratospheric Balloons Using Reinforcement Learning." *Nature* 588 (7836): 77–82. https://doi.org/10.1038/s41586-020-2939-8.

27 Bellemare, M.G., Candido, S., Castro, P.S., Gong, J. Machado, M.C., Moitra, S., Ponda, S.S., et al. 2020. "Autonomous Navigation of Stratospheric Balloons Using Reinforcement Learning." *Nature* 588 (7836): 77–82. https://doi.org/10.1038/s41586-020-2939-8.

28 Jacob, D.J., Varon, D.J., Cusworth, D.H., Dennison, P.E., Frankenberg, C., Gautam, R., Guanter, L., Kelley, J., McKeever, J., Ott, L.E., Poulter, B., Qu, Z., Thorpe, A.K., Worden, J. R., and Duren, R.M. 2022. "Quantifying methane emissions from the global scale down to point sources using satellite observations of atmospheric methane." *Atmospheric Chemistry and Physics* 22, 9617–9646. https://doi.org/10.5194/acp-22-9617-2022.

quantifying methane emissions can be grouped as area-flux mappers and point-source imagers.

Area-flux mappers provide accurate measurements globally with a spatial resolution of several kilometers. The TROPOspheric Monitoring Instrument (TROPOMI) mission is the main area-flux mapping satellite in operation in 2023. TROPOMI has a spatial resolution of ~5.5 km^2 x 7 km^2 with daily global coverage and been used to detect large methane emissions events (>1,000 kg/hr) around the world.[29, 30] The satellites from the

29 Lauvaux, T., Giron, C., Mazzolini, M., d'Aspremont, A., Duren, R., Cusworth, D., Shindell, D., and Ciais, P. 2022. "Global Assessment of Oil and Gas Methane Ultra-Emitters." *Science*375 (6580): 557–61. https://doi.org/10.1126/science.abj4351.

30 Maasakkers, J.D., Varon, D.J., Elfarsdóttir, A., McKeever, J., Jervis, D., Mahapatra, G., Pandey, S., et al. 2022. "Using Satellites to Uncover Large Methane Emissions from Landfills." *Science Advances*8 (32). https://doi.org/10.1126/sciadv.abn9683.

Spatial Coverage	Satellite	Agency	Data Available	Pixel Size	Revisit Frequency	Data Availability	Point-Source Detection Limit (kg/hr)
Global	GOSAT/ GOSAT-2	JAXA	2009- /2018-	10 x 10 km	3 days each satellite	Free	7,000 / 4,000
Global and regional	TROPOMI	ESA	2017-	7 x 5.5 km	1 day	Free	4,000
Global and regional	Sentinel-5	ESA	Expected 2024	7.5 x 5.5 km	1 day	Free	4,000
Regional	MethaneSAT	EDF	Expected 2024	130 x 400 m	3–4 days	Free	1,000
Individual point sources	Landsat 8 and 9	NASA	2013- /2021-	30 x 30 m	16 days each satellite	Free	900
Individual point sources	Sentinel-2 (A+B)	ESA/EU	2015 -	20 x 20 m	5 days	Free	900
Individual point sources	PRISMA	ASI	2019 -	30 x 30 m	4 days	Free	500
Individual point sources	EnMAP	DLR	2022 -	30 x 30 m	4 days	Free	500
Individual point sources	EMIT	NASA	2022 -	60 x 60 m	3 days	Free	500
Individual point sources	WorldView-3	MAXAR	2014 -	3.7 x 3.7 m	<1 days	payment	<100
Individual point sources	GHGSat	GHGSat, Inc.	2016 -	25 x 25 m	1–7 days	payment	200
Individual point sources	Carbon Mapper	Carbon Mapper and Planet	Expected 2024	30 x 30 m	1–7 days	TBD	100

***Table D-8.** Methane-Measuring Satellites Systems*

Greenhouse Gases Observing Satellite (GOSAT) family are also area-flux mappers. GOSAT and GOSAT-2 have high spectral resolution, but their spatial sampling is sparse, while the upcoming GOSAT-GW has similar characteristics to TROPOMI.

Point-source, hyperspectral imagers enable the detection and quantification of large methane plumes at high spatial resolution (20 m–50 m) but have relatively poor spatial coverage and are typically tasked to make measurements at specific sites by the satellite operators. Point-source multispectral imagers (e.g., Sentinel-2 and Landsat-8 and 9) provide global coverage but have higher detection limits than hyperspectral instruments.

Finally, the gap between area-flux mappers with coarse spatial resolution but global coverage and point-source imagers with high spatial resolution but sparse coverage will be covered by the MethaneSAT mission, which combines a sub-kilometer spatial sampling with broad coverage.

Details on the observational characteristics of most of those satellite missions capable of detecting point-source super-emitters are listed in Table D-8. This summary was developed by the EPA Science Advisory Board (2023).[31] The detection limits in Table D-8 reflect ideal observing conditions and are highly variable.

31 EPA Science Advisory Board. 2024. "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Segment Climate Review." https://www.federalregister.gov/documents/2024/03/08/2024-00366/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for.

Appendix E-1

LITERATURE COLLECTION KEYWORDS

Keywords Used
greenhouse gas analysis or GHG analysis, shale gas or fossil gas
life cycle assessment or LCA, natural gas, supply chain
carbon footprinting or carbon foot printing, shale gas or fossil gas or natural gas or methane or LNG or liquefied natural gas
carbon footprinting or carbon foot printing, shale gas or fossil gas or natural gas or methane or LNG or liquefied natural gas
greenhouse gas analysis or greenhouse gas emissions or GHG analysis or GHG emissions, shale gas or fossil gas or natural gas or methane or LNG or liquefied natural gas
greenhouse gas analysis or greenhouse gas emissions or GHG analysis or GHG emissions, shale gas or fossil gas or natural gas or methane or LNG or liquefied natural gas
life cycle analysis or lifecycle analysis or life-cycle analysis, shale gas or fossil gas or natural gas or methane or LNG or liquefied natural gas
life cycle analysis, natural gas, liquefied
life cycle analysis, natural gas, supply chain
life cycle assessment or lifecycle assessment or life-cycle assessment or LCA, shale gas or fossil gas or natural gas or methane or LNG or liquefied natural gas

Table E-1. *List of Keywords Used for Literature Collection*

Appendix E-2

SYSTEMATIC LITERATURE REVIEW DETAILS AND SCREENING CRITERIA

The Life Cycle Assessment (LCA) literature was systematically assessed via data mining of Google Scholar.[1] Only studies published since 2016 were considered. Google Scholar was chosen as the primary method of data collection, as it has been found to produce a comprehensive set of results for systematic reviews in comparison to similar databases, such as Web of Science. Web scraping is a process by which information is collected from websites (Google Scholar, in this case). It can be automated using programming languages such as Python. Considering the volume of results, a Python web scraper was used for collecting literature, the code for which is available online (Jordaan et al., 2022).[2] Python scraping is a form of web scraping, in which Python-based code is used to automate collection and storage of large amounts of data from the web. The scraper was coded to collect relevant information about the studies searched and store them in a spreadsheet. Information collected included the title of the study, author(s), year published, description, journal, publisher, and URL for the study.

The keywords used for literature collection were selected by the authors, as informed by prior harmonization studies with feedback from subject matter experts (SMEs) participating in the National Petroleum Council (NPC) study. Only studies published since 2016 were considered to represent studies completed after the Environmental Protection Agency (EPA) updated the New Source Performance Standards and Permitting Requirements rules for oil and gas industry.[3] Refer to Table E-1 in Appendix E-1 for the list of keywords used for literature search.

Regarding literature included for harmonization, the focus is on products where natural gas is used as a fuel. LCAs whose final product was other energy carriers and chemicals or plastics were excluded. LCAs whose product of focus was electricity, LNG, and compressed natural gas (CNG) were deemed acceptable for further screening so long as their results could be adjusted to apply just to the three gates described in Chapter 4.

A. Screening Criteria

Screening started at the level of articles and proceeded to the level of individual estimates. Estimate-level screening was required because each study might report more than one estimate of life cycle greenhouse gas (GHG) emissions based on multiple scenarios, supply chains, locations, etc. The screening criteria for each stage are described in Table E-2. This was a rigorous and iterative process following the above-cited global guidance on screening decisions and quality control. The study team reviewed 2,229 articles and collected characteristics of each study. Additionally, data was collected on which stage of screening a study failed and reasons for acceptance/rejection of a study in every stage of screening.

1 https://scholar.google.com

2 Jordaan, S.M., Ruttinger, A.W., Surana, K., Nock, D., Miller, S.M., and Ravikumar, A.P. 2022. Global mitigation opportunities for the life cycle of natural gas-fired power. *Nature Climate Change, 12(11), 1059–1067.* https://doi.org/10.1038/s41558-022-01503-5.

3 EPA. "New Source Performance Standards and Permitting Requirements." September 27, 2016. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations/new-source-performance-standards-and.s.

Stage	Criteria
Stage 1	Remove duplicated articles.
	Remove articles fewer than three published pages in length.
	Remove conference proceedings fewer than five double-spaced pages in length.
	Remove references not written in English.
	Remove abstracts, conference posters, and PowerPoint presentations.
Stage 2	Retain articles that perform LCA and confirm the type of LCA (e.g., cradle-to-gate).
	Retain articles that consider carbon dioxide emissions and methane emissions from natural gas supply chain.
	Retain references published after the year 2016.
	Retain references relevant to natural gas and the production of natural gas.
Stage 3A	3A.1. Methane emissions data utilized must be representative of the year 2016 or a later period, i.e., studies that explicitly indicate their characterization of the specific year or similar expressions.
	3A.2. In the absence of clear indications in #3A.1, the EPA GHG inventory publications for the year 2016 or later should be referenced.
	3A.3. If neither #3A.1 nor #3A.2 is available, the data vintage of methane leakage data sources should be characterized, focusing on cited publications with publication years of 2016 or later.
Stage 3B	3B.1. Retain articles that employ a currently accepted LCA method (e.g., must adhere to [ISO] 14040 series standards; 14067 series standards) or use common models developed by National Laboratories or peer-reviewed publications.
	3B.2. Retain articles that report a functional unit in the LCA process.
	3B.3. Retain articles that provide transparent reporting of methods, assumptions, and technology descriptions.
Stage 4	4.1. Remove duplicative estimates (i.e., studies that reported life cycle GHG emissions estimates from previous studies, with no update or modification to the estimate).
	4.2. Remove estimates that resulted from sensitivity analyses or by varying one parameter with no other difference in methods to differentiate the estimate from other estimates in the study.

Note: The screening criteria were used in four stages, each with three to five criteria, as outlined in the table.

***Table E-2.** Screening Criteria*

Appendix E-3

STUDY POOL SUMMARY

Study	Full Citation
Cai et al., 2017	Cai, H., Burnham, A., Chen, R., and Wang, M. 2017. "Wells to Wheels: Environmental Implications of Natural Gas as a Transportation Fuel." *Energy Policy*, *109*, 565–578. https://doi.org/https://doi.org/10.1016/j.enpol.2017.07.041.
	Data sources: GREET, 2016: https://doi.org/10.11578/GREET-Net-2016/dc.20200803.10. EPA, 2016: EPA Greenhouse Reporting Program Data Sets.
Meng and Dillingham, 2018	Meng, Fanxu, and Gavin Dillingham. 2018. "Life Cycle Analysis of Natural Gas-Fired Distributed Combined Heat and Power Versus Centralized Power Plant." *Energy and Fuels*, *32*(11), 11731–11741. https://doi.org/10.1021/acs.energyfuels.8b02949.
	Data source: NETL, 2016: National Energy Technology Laboratory Annual Report, 2016. https://netl.doe.gov/sites/default/files/publication/2016AR.pdf.
Balcombe et al., 2018	Balcombe, P., Brandon, N.P., and Hawkes, A.D. 2018. "Characterising the Distribution of Methane and Carbon Dioxide Emissions from the Natural Gas Supply Chain." *Journal of Cleaner Production*, 172, 2019–2032. https://doi.org/10.1016/j.jclepro.2017.11.223.
	Data sources: Balcombe et al., 2015: Balcombe, P., Anderson, K., Speirs, J., Brandon, N., and Hawkes, A. 2015. "Methane and CO_2 Emissions from the Natural Gas Supply Chain: An Evidence Assessment." In: *Sustainable Gas Institute*. Imperial College London. Balcombe et al., 2017: Balcombe, P., Anderson, K., Speirs, J., Brandon, N., and Hawkes, A. 2017. "The Natural Gas Supply Chain: The Importance of Methane and Carbon Dioxide Emissions." *ACS Sustainable Chemistry & Engineering*. https://doi.org/10.1021/acssuschemeng.6b00144.
Tanaka et al., 2019	Tanaka, K., Cavalett, O., Collins, W.J., and Cherubini, F. 2019. "Asserting the Climate Benefits of the Coal-to-Gas Shift Across Temporal and Spatial Scales." *Nature Climate Change*, 9(5), 389–396. https://doi.org/10.1038/s41558-019-0457-1.
	Data source: Ecoinvent v3.4, 2017: https://support.ecoinvent.org/ecoinvent-version-3.4.
Roman-White et al., 2019	Roman-White, S., Rai, S., Littlefield, J., Cooney, G., and Skone, T.J. 2019. "Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States: 2019 Update." DOE/NETL. https://www.energy.gov/sites/prod/files/2019/09/f66/2019%20NETL%20LCA-GHG%20Report.pdf.
	Data source: EPA, 2016: EPA Greenhouse Reporting Program Data Sets. EPA, 2018: EPA Greenhouse Reporting Program Data Sets.
Winebrake et al., 2019	Winebrake, J.J., Corbett, J.J., Umar, F., and Yuska, D. 2019. "Pollution Tradeoffs for Conventional and Natural Gas-Based Marine Fuels." In *Sustainability* (Vol. 11, Issue 8). https://doi.org/10.3390/su11082235.
	Data source: GREET, 2018: https://doi.org/10.11578/GREET-Net-2018/dc.20200803.8.

Table E-3. *List of Studies and Their Data Sources in the Final Study Pool (Table E-4) with Their Full Citation Information*

Study	Full Citation
Crow et al., 2019	Crow, D.J.G., Balcombe, P., Brandon, N., and Hawkes, A.D. 2019. "Assessing the Impact of Future Greenhouse Gas Emissions from Natural Gas Production." *Science of The Total Environment*, *668*, 1242–1258. https://doi.org/https://doi.org/10.1016/j.scitotenv.2019.03.048.
	Data source: Balcombe et al., 2017: Balcombe, P., Anderson, K., Speirs, J., Brandon, N., and Hawkes, A. 2017. "The Natural Gas Supply Chain: The Importance of Methane and Carbon Dioxide Emissions." *ACS Sustainable Chemistry & Engineering*. https://doi.org/10.1021/acssuschemeng.6b00144.
Roman-White et al., 2021	Roman-White, S.A., Littlefield, J.A., Fleury, K.G., Allen, D.T., Balcombe, P., Konschnik, K.E., Ewing, J., Ross, G.B., and George, F. 2021. "LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting." *ACS Sustainable Chemistry & Engineering*, 9(32), 10857–10867. https://doi.org/10.1021/acssuschemeng.1c03307.
	Data source: EPA, 2018: EPA Greenhouse Reporting Program Data Sets.
Rai et al., 2021	Rai, S., Littlefield, J., Roman-White, S., Zaimes, G.G., Cooney, G., and Skone, T.J. 2021. "Industry Partnerships & Their Role in Reducing Natural Gas Supply Chain Greenhouse Gas Emissions – Phase 2." OSTI.gov. February 12, 2021. Report number DOE/NETL-2020/2607. https://doi.org/10.2172/1647225.
	Data source: Littlefield et al., 2019: Littlefield, J., Roman-White, S., Augustine, D.J., Pegallapati, A., Zaimes, G.G., Rai, S., Cooney, G., and Skone, T.J. 2019. "Life Cycle Analysis of Natural Gas Extraction and Power Generation." DOE/NETL-2019/2039. DOE NETL. https://www.netl.doe.gov/energyanalysis/details?id=3198.
Balcombe et al., 2021	Balcombe, P., Staffell, I., Kerdan, I.G., Speirs, J.F., Brandon, N.P., and Hawkes, A.D. 2021. "How Can LNG-Fuelled Ships Meet Decarbonisation Targets? An Environmental and Economic Analysis." *Energy*, *227*, 120462. https://doi.org/10.1016/j.energy.2021.120462.
	Data sources: Balcombe et al., 2015: Balcombe, P., Anderson, K., Speirs, J., Brandon, N., and Hawkes, A. 2015. "Methane and CO_2 Emissions from the Natural Gas Supply Chain: An Evidence Assessment." In: *Sustainable Gas Institute*. Imperial College London. Balcombe et al., 2017: Balcombe, P., Anderson, K., Speirs, J., Brandon, N., and Hawkes, A. 2017. "The Natural Gas Supply Chain: The Importance of Methane and Carbon Dioxide Emissions." *ACS Sustainable Chemistry & Engineering*. https://doi.org/10.1021/acssuschemeng.6b00144.
Contreras et al., 2021	Contreras, W., Hardy, C., Tovar, K., Piwetz, A.M., Harris, C.R., Tullos, E.E., Bymaster, A., McMichael, J., and Laurenzi, I.J. 2021. "Life Cycle Greenhouse Gas Emissions of Crude Oil and Natural Gas from the Delaware Basin." *Journal of Cleaner Production*, 328(October), 129530. https://doi.org/10.1016/j.jclepro.2021.129530.
	Data source: Bridger, 2019: Bridger Photonics Gas Mapping LiDAR™. https://www.bridgerphotonics.com/gas-mapping-lidar/.
Littlefield et al., 2022	Littlefield, J., Rai, S., and Skone, T.J. 2022. "Life Cycle GHG Perspective on U.S. Natural Gas Delivery Pathways." *Environmental Science & Technology*, *56*(22), 16033–16042. https://doi.org/10.1021/acs.est.2c01205.
	Data source: EPA, 2018: EPA Greenhouse Reporting Program Data Sets.
Kelly et al., 2022	Kelly, J.C., Elgowainy, A., Issac, R., Ward, J., Islam, E., Rousseau, A., Sutherland, I., Wallington, T.J., Alexander, M., Muratori, M., Franklin, M., Adams, J., and Rustagi, N. 2022. "Cradle-to-Grave Lifecycle Analysis of U.S. Light-Duty Vehicle-Fuel Pathways: A Greenhouse Gas Emissions and Economic Assessment of Current (2020) and Future (2030-2035) Technologies." https://publications.anl.gov/anlpubs/2022/07/176270.pdf.
	Data source: GREET, 2020a: https://doi.org/10.11578/GREET-Net-2020/dc.20200913.1.
Jordaan et al., 2022	Jordaan, S.M., Ruttinger, A.W., Surana, K., Nock, D., Miller, S.M., and Ravikumar, A.P. 2022. "Global Mitigation Opportunities for the Life Cycle of Natural Gas-Fired Power." *Nature Climate Change*, 12(11), 1059–1067. https://doi.org/10.1038/s41558-022-01503-5.
	Data source: EPA, 2019: EPA Greenhouse Reporting Program Data Sets.

***Table E-3.** List of Studies and Their Data Sources in the Final Study Pool (Table E-4) with Their Full Citation Information (continued)*

Study	Full Citation
Rai et al., 2022	Rai, S., Hage, D., Littlefield, J., Yanai, G., and Skone, T.J. 2022. "Comparative Life Cycle Evaluation of the Global Warming Potential (GWP) Impacts of Renewable Natural Gas Production Pathways." *Environmental Science & Technology*, 56(12), 8581–8589. https://doi.org/10.1021/acs.est.2c00093.
	Data source: Not specified
GREET, 2022	https://doi.org/10.11578/GREET-Net-2022/dc.20220908.2.
	Data sources: EPA, 2022: EPA Greenhouse Reporting Program Data Sets; Rutherford et al., 2021: Rutherford et al., 2021: Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P., Heath, G.A., Englander, J., Cooley, D., Lyon, D., et al. 2021. "Closing the Methane Gap in U.S. Oil and Natural Gas Production Emissions Inventories." *Nature Communications* 12(1). https://www.nature.com/articles/s41467-021-25017-4; Alvarez et al., 2018: Alvarez, R.A., Zavala-Araiza, D., Lyon, D.R., Allen, D.T., Barkley, Z.R., Brandt, A.R., Davis, K.J., et al. 2018. "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain." *Science* 361 (6398): eaar7204. https://doi.org/10.1126/science.aar7204.

Table E-3. *List of Studies and Their Data Sources in the Final Study Pool (Table E-4) with Their Full Citation Information (continued)*

Study	Gas Type Conventional/ Unconventional	Geographical Representativeness of Production Region	End Product	Units of Life Cycle Results	System Boundaries	Harmonized Methane Emissions Rates (% in g CH_4 emitted/ g NG delivered)	Key Methane Data Source(s)/ Publication Year	Key Methane Data Source, Use of Measurements
Cai et al., 2017	Conventional and unconventional (shale)	U.S. national average	Natural gas fuel for Heavy Duty Vehicles (HDVs)	g CO_2/ ton-mile g CO_2/ passenger-mile	Production to LNG delivery	1.42% (conventional) 1.50% (shale)	GREET, 2016 EPA, 2016	Blended EPA with published measurements
Meng and Dillingham, 2018	Conventional and unconventional (unspecified)	U.S. national average*	Electricity	kg CH_4/ kg NG delivered to plan kg CO_2/ kg NG delivered to plan	Production to transmission	1.52%	NETL, 2016	Blended EPA with published measurements
Balcombe et al., 2018	Conventional and unconventional (shale and tight)	U.S. national average	LNG	g CO_2 eq/ MJ	Production to distribution	0.67%–1.85%	Balcombe et al., 2015 Balcombe et al., 2017	LCA datasets with published measurements
Tanaka et al., 2019	Conventional and unconventional (unspecified)	Mixture of basins	Electricity	g CO_2/ kWhr g CH_4/ kWhr	Production to distribution	1.23%	Ecoinvent v3.4, 2017	LCA datasets
Roman-White et al., 2019	Unconventional (shale)	Appalachia	Electricity	kg CO_2e/ MWhr	Production to LNG delivery	0.70% 1.10%–1.20%	EPA, 2016 EPA, 2018	EPA
Winebrake et al., 2019	Conventional and unconventional (unspecified)	U.S. national average*	LNG as marine fuel	g CO_2e/MJ	Production to LNG delivery	1.09% 1.11% 1.61%	GREET, 2018	Blended EPA with published measurements
Crow et al., 2019	Conventional and unconventional (unspecified)	U.S. national average	LNG	g CH_4/m3 g CO_2/m^3	Recovery (preproduction and production)	-	Balcombe et al., 2017	LCA datasets with published measurements
Roman-White et al., 2021	Conventional and unconventional (unspecified)	Cheniere's SPL LNG supply chain, U.S. national average	LNG	t CO_2/t NG regasified g CO_2e/MJ regasified	Production to LNG delivery	0.64% 0.78%	EPA, 2018	EPA

Table E-4. *Summary of the Studies in the Final Study Pool*

Study	Gas Type Conventional/ Unconventional	Geographical Representativeness of Production Region	End Product	Units of Life Cycle Results	System Boundaries	Harmonized Methane Emissions Rates (% in g CH_4 emitted/ g NG delivered)	Key Methane Data Source(S)/ Publication Year	Key Methane Data Source, Use of Measurements
Rai et al., 2021	Conventional and unconventional (unspecified)	ONEFUTURE supply chain average, U.S. national average	Natural gas supply chains	g CO_2 eq/ MJ	Production to distribution	0.76% 1.06%	Littlefield. et al., 2019	Blended EPA with published measurements
Balcombe et al., 2021	Conventional and unconventional (unspecified)	U.S. national average	LNG as marine fuel	kg CO_2 eq/ kWhr	Production to LNG delivery	1.03%	Balcombe et al., 2015 Balcombe et al., 2018	LCA datasets with published measurements
Contreras et al., 2021	Unconventional (shale)	Delaware Basin	Electricity	g CO_2e/MJ LHV NG	Production to transmission	0.66% 0.92%	Bridger, 2019	Direct measurements
Littlefield et al., 2022	Conventional and unconventional (unspecified)	U.S. national average, six regional averages	Natural gas supply chains	g CO_2e/MJ delivered	Production to distribution	0.97%	EPA, 2018	EPA
Kelly et al., 2022	Conventional and unconventional (shale)	U.S. national average*	Compressed natural gas fuel for Light Duty Vehicles (LDVs)	g CO_2e/ mile	Production to LNG delivery	0.75% 0.77% 1.45%	GREET, 2020a	Blended EPA with published measurements
Jordaan et al., 2022	Conventional and unconventional (unspecified)	U.S. national average	Electricity	g CO_2e/ kWhr	Production to transmission	0.24% 0.19%	EPA, 2019	EPA
Rai et al., 2022	Conventional and unconventional (unspecified)	U.S. national average*	Renewable natural gas with fossil natural gas input	g CO_2 eq/ MJ	Production to processing	Not specified	Not specified	Not specified
GREET, 2022	Conventional and unconventional (shale)	U.S. national average	Natural gas fuel for vehicles	g CH_4/ MMBtu NG	Production to LNG delivery	0.80% 0.81% 1.12%	EPA, 2022; Rutherford et al., 2021; Alvarez et al., 2018	Blended EPA with published measurements

Note: Based on a U.S. average natural gas profile or U.S. average natural gas mix.

Table E-4. *Summary of the Studies in the Final Study Pool (continued)*

Appendix E-4

HARMONIZATION METHODOLOGY

The total number of GHG life cycle estimates from the above process was 32 for results reported using GWP100 and 28 for results reported to GWP20.

As discussed in Chapter 4, harmonization was applied to both the numerator and denominator of the life cycle GHG emissions intensity metric, g CO_2e/MJ. Life cycle GHG emissions estimates across different studies were reported in different units. All 32 emissions estimates across different studies were hence converted to the common unit of g CO_2 (or) g CH_4 (or) g CO_2e per MJ natural gas delivered using data from standard sources such as EPA and Energy Information Administration (EIA) to complete the unit conversion (e.g., heating value).

The steps of harmonization proceeded in the following order:

1. Alignment to gate boundaries, including adders, for when distribution or LNG shipping was missing
2. Use of consistent GWP100 and GWP20 values
3. Inclusion of important natural gas supply chain processes: preproduction and liquids unloading

Figure E-1 summarizes the steps of harmonization and notes to how many estimates (GWP100 and GWP20 estimates separately) each step was applied.

The first stage of harmonization was harmonizing all the estimates to three different gates. Estimates without stagewise breakdown (six out of 32 for GWP100 and five out of 28 for GWP20) were placed at a gate that aligns with its system boundaries.

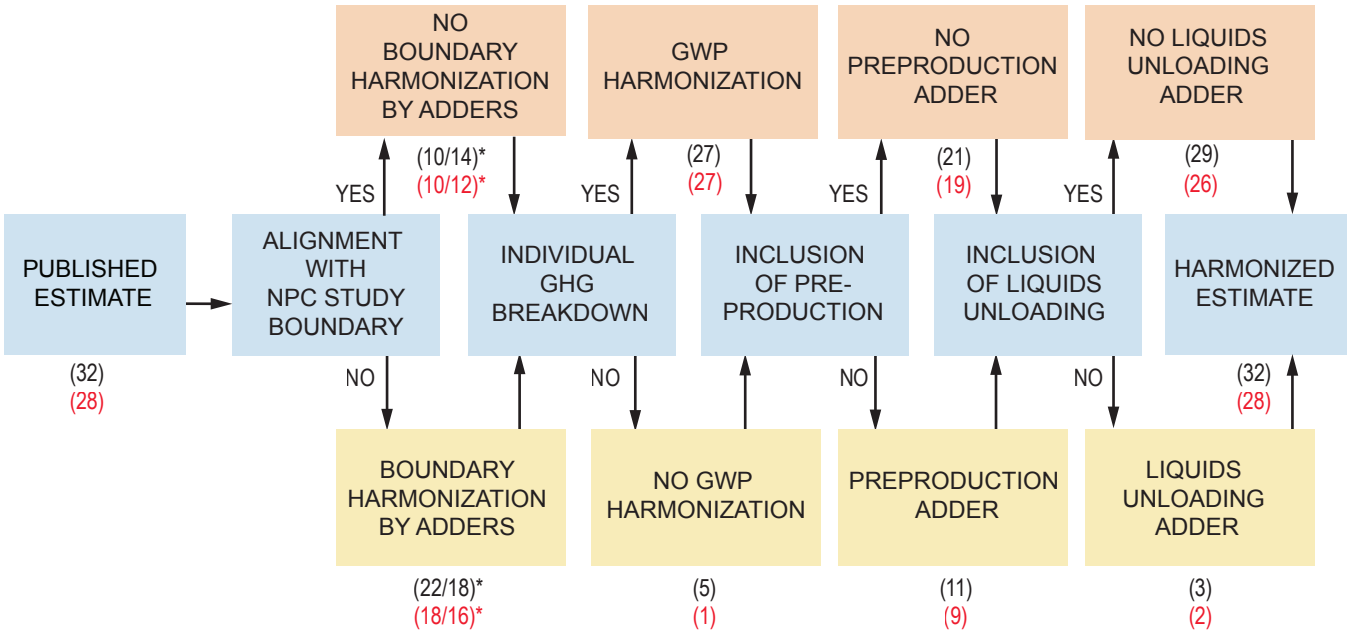
For estimates that have a system boundary that fall short of the harmonized gate, adders were developed following the methodology in prior harmonization studies (see especially O'Donoughue et al., 2014[4]) and based on averages for stage-specific emissions reported by studies passing the systematic review screens that included that stage.

Table E-5 shows the values and representativeness for the adders. It must be noted that these adders were used wherever necessary, irrespective of the differences in the distribution system size and shipping distances.

Another harmonization step for the numerator was global warming potential (GWP) harmonization. Out of the 32 estimates, 27 reported speciated GHG results. The GWPs used in different studies are documented in Table E-4. Emissions estimates without speciated results (five estimates) could not be harmonized by GWP. Out of these, one used a GWP of 28—effectively making it a GWP harmonized estimate since it did not differ significantly from the GWP used in this study. Four estimates used a GWP of 36, which were not harmonized to GWP due to lack of speciation. It must be noted that this might have caused a minor overestimation in our harmonized estimates.

Using methods developed in O'Donoghue et al., (2014), CH_4 emissions for the functional unit

4 O'Donoughue, P.R., Heath, G.A., Dolan, S.L., and Vorum, M. 2014. "Life Cycle Greenhouse Gas Emissions of Electricity Generated from Conventionally Produced Natural Gas." *Journal of Industrial Ecology* 18 (1): 125–44. https://doi.org/10.1111/jiec.12084.



Notes: The 16 studies passing screens reported 32 distinct estimates of life cycle GHG emissions using GWP100 and 28 estimates using GWP20.

* The two different numbers in the boundary harmonization step refer to the number of estimates that required that step for production through distribution and LNG shipping, respectively.

Figure E-1. *Harmonization Methodology (Number of Estimates Subjected to Each Step for GWP100 and GWP20 Harmonization in Parentheses)*

(1 MJ of natural gas delivered), were scaled by their respective GWP impact factors, summed, and then adjusted by the ratio of our harmonized GWP and the GWP from the sourced study. To understand the GWP harmonization method, it is important to understand how life cycle GHG emissions were estimated. O'Donoghue et al., (2014), provides the basic equation:

$$g\ CO_2e = g\ CO_2 + gCH_4 \times GWP$$

where $g\ CO_2e$ = CO_2 equivalent of the emissions estimate in grams per MJ of natural gas delivered

GWP Time Period	Adder Boundary	Adder Value (g CO_2e/MJ NG)	Number of Estimates Averaged to Calculate the Adder
100 yr	Distribution	1.3	9
	LNG Shipping	10	9
20 yr	Distribution	2.6	9
	LNG Shipping	12	4

Table E-5. *Adders Used for Harmonization*

g CO_2 = CO_2 emitted, in grams per MJ of natural gas delivered

g CH_4 = CH_4 emitted, in grams per MJ of natural gas delivered

GWP = Global Warming Potential of CH_4 used in the study (g CO_2/g CH_4)

The methodology for GWP harmonization follows O'Donoghue, et al., 2014, which is as follows:

$$A' = A_1 + A_2 * GWP * x'/x$$

where A' = Harmonized life cycle emissions estimate in g CO_2e/MJ natural gas delivered

A1 = CO_2 emitted, in grams per MJ of natural gas delivered

A2 = CH_4 emitted, in grams per MJ of natural gas delivered

GWP = Global Warming Potential used in the study (g CO_2/g CH_4)

x' = Harmonized GWP

x = Global Warming Potential used in the study (g CO_2/g CH_4)

Study	100-yr CH_4 GWP	20-yr CH_4 GWP	Reference/Data Source
Cai et al., 2017	28	84	IPCC AR5[1]
Roman-White et al., 2019	36	87	
Tanaka et al., 2019	30	85	
Winebrake et al., 2019	28	84	
Balcombe et al., 2021	36	87	
Contreras et al., 2021	30	85	
Rai et al., 2021	36	87	
Roman-White et al., 2021	36	87	
Jordaan et al., 2022	30	85	
Kelly et al., 2022	30	85	
Littlefield et al., 2022	36	87	
Rai et al., 2022	36	87	
GREET, 2022	29.8	82.5	IPCC AR6[2]
Balcombe et al., 2018	34	86	Zammerilli et al., 2014
Meng and Dillingham, 2018	36	87	IPCC AR5,[3] NETL 2016[4]
Crow et al., 2019	Dynamic GWP	Dynamic GWP	

1 IPCC. 2014. "AR5 Synthesis Report: Climate Change 2014." https://www.ipcc.ch/report/ar5/syr/.

2 IPCC. 2023. "IPCC, 2023: Synthesis Report. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change." https://doi.org/10.59327/ipcc/ar6-9789291691647.

3 IPCC. 2014. "AR5 Synthesis Report: Climate Change 2014." https://www.ipcc.ch/report/ar5/syr/.

4 Littlefield, J., Augustine, D., Pegallapati, A., Zaimes, G., Rai, S., and Cooney, G. 2019. "Life cycle analysis of natural gas extraction and power generation." U.S. DOE Office of Scientific and Technical Information, April 19, 2019. https://doi.org/10.2172/1529553.

Table E-6. *GWP Reported in Each Study*

As mentioned earlier, emissions estimates reported in g CO_2e without speciated results (four out of 32) were not harmonized by GWP. Table E-5 lists the GWPs used in each study. As discussed, all the studies with nonspeciated results have a GWP higher than the AR5 GWP used for harmonization, causing a minor overestimation in our harmonized estimates.

The last step of harmonization involved preproduction and liquids-unloading adders for those studies that omitted the emissions associated with these activities. Multiple studies excluded supply chain stages common to each NPC-study gate, specifically, activities associated with preproduction and liquids unloading. Thus, like the adders described previously, they were developed for preproduction and liquids unloading emissions, which can be found in Table E-6. While these emissions seem small with respect to total life cycle emissions, they are necessary to ensure a commensurate system boundary.

GWP (g CO_2/g CH_4)	Adder Emissions Source	Adder Value (g CO_2e/ MJ NG)	Number of Estimates Averaged to Calculate the Adder
100	Preproduction	0.3	5
	Liquids unloading	0.6	11
20	Preproduction	0.3	5
	Liquids unloading	1.7	11

Table E-7. *Adders Used for Harmonization for Preproduction and Liquids Unloading*

Steps → Estimate ↓	Transmission Adder	Distribution Adder	LNG Segment Adder	GWP Harmonization	Preproduction Adder	Liquids-unloading Adder	Estimate Boundaries	Estimates Reported per Stage
Cai et al., 2017	No	Yes	No	No	No	No	Production to LNG delivery	No
Balcombe et al., 2018	No	No	Yes	Yes	No	No	Production to distribution	No
Meng and Dillingham, 2018	No	Yes	Yes	Yes	Yes	No	Production to transmission	No
Crow et al., 2019; Conventional	Yes	Yes	Yes	Yes	No	No	Recovery (preproduction and production)	Yes
Crow et al., 2019; Unconventional	Yes	Yes	Yes	Yes	No	No	Recovery (preproduction and production)	Yes
Roman-White et al., 2019; Rotterdam (GWP100)	No	Yes	No	Yes	Yes	No	Production to LNG delivery	Yes
Roman-White et al., 2019; Shanghai (GWP100)	No	Yes	No	No	Yes	No	Production to LNG delivery	Yes
Tanaka et al., 2019	No	Yes	Yes	Yes	Yes	Yes	Production to transmission	No
Winebrake et al., 2019; EDF emissions factor (high)	No	Yes	No	Yes	No	No	Production to LNG delivery	Yes
Winebrake et al., 2019; EPA emissions factor (low)	No	Yes	No	Yes	No	No	Production to LNG delivery	Yes
Winebrake et al., 2019; Mean	No	Yes	No	Yes	No	No	Production to LNG delivery	Yes
Balcombe et al., 2021; HPDF 2-stroke	No	Yes	No	Yes	Yes	No	Production to LNG delivery	Yes
Balcombe et al., 2021; LBSI	No	Yes	No	Yes	Yes	No	Production to LNG delivery	Yes
Balcombe et al., 2021; LPDF 2-stroke	No	Yes	No	Yes	Yes	No	Production to LNG delivery	Yes
Balcombe et al., 2021; LPDF 4-stroke	No	Yes	No	Yes	Yes	No	Production to LNG delivery	Yes
Contreras et al., 2021; Life cycle-stage allocation	No	Yes	Yes	No	No	Yes	Production to transmission	Yes

Table E-8. *Harmonization of Each Study, GWP100*

Steps → Estimate ↓	Transmission Adder	Distribution Adder	LNG Segment Adder	GWP Harmonization	Preproduction Adder	Liquids-unloading Adder	Estimate Boundaries	Estimates Reported per Stage
Contreras et al., 2021; Process unit-level allocation[5]	No	Yes	Yes	No	No	Yes	Production to transmission	Yes
Rai et al., 2021; ONE Future GWP100	No	No	Yes	Yes	No	No	Production to distribution	Yes
Rai et al., 2021; U.S. average GWP100	No	No	Yes	Yes	No	No	Production to distribution	Yes
Roman-White et al., 2021; China	No	Yes	No	Yes	Yes	No	Production to LNG delivery	Yes
Roman-White et al., 2021; UK	No	Yes	No	Yes	Yes	No	Production to LNG delivery	Yes
GREET, 2022	No	Yes	No	Yes	No	No	Production to LNG delivery	No
Jordaan et al., 2022	No	Yes	Yes	Yes	No	No	Production to transmission	Yes
Kelly et al., 2022; GREET, 2020	No	Yes	No	Yes	No	No	Production to LNG delivery	No
Littlefield et al., 2022; MW	No	No	Yes	Yes	No	No	Production to distribution	Yes
Littlefield et al., 2022; NE	No	No	Yes	Yes	No	No	Production to distribution	Yes
Littlefield et al., 2022; Pacific	No	No	Yes	Yes	No	No	Production to distribution	Yes
Littlefield et al., 2022; Rocky	No	No	Yes	Yes	No	No	Production to distribution	Yes
Littlefield et al., 2022: SE	No	No	Yes	Yes	No	No	Production to distribution	Yes
Littlefield et al., 2022; SW	No	No	Yes	Yes	No	No	Production to distribution	Yes
Littlefield et al., 2022; U.S. average	No	No	Yes	Yes	No	No	Production to distribution	Yes
Rai et al., 2022	Yes	Yes	Yes	No	Yes	No	Production to processing	Yes

5 Contreras et al., 2021, assessed associated gas which does not require liquids unloading operations typical of nonassociated gas, and thus, an adder was not required.

Table E-8. *Harmonization of Each Study, GWP100 (continued)*

Steps → Estimate ↓	Transmission Adder	Distribution Adder	LNG Segment Adder	GWP Harmonization	Preproduction Adder	Liquids-unloading Adder	Estimate Boundaries	Estimates Reported per Stage
Balcombe et al., 2018	No	No	Yes	Yes	No	No	Production to distribution	No
Meng and Dillingham, 2018	No	Yes	Yes	Yes	Yes	No	Production to transmission	No
Crow et al., 2019; Conventional	Yes	Yes	Yes	Yes	No	No	Recovery (preproduction and production)	Yes
Crow et al., 2019; Unconventional	Yes	Yes	Yes	Yes	No	No	Recovery (preproduction and production)	Yes
Roman-White et al., 2019; Rotterdam (GWP100)	No	Yes	No	Yes	Yes	No	Production to LNG delivery	Yes
Tanaka et al., 2019	No	Yes	Yes	Yes	Yes	Yes	Production to transmission	No
Winebrake et al., 2019; EDF emissions factor (high)	No	Yes	No	Yes	No	No	Production to LNG delivery	Yes
Winebrake et al., 2019; EPA emissions factor (low)	No	Yes	No	Yes	No	No	Production to LNG delivery	Yes
Winebrake et al., 2019; Mean	No	Yes	No	Yes	No	No	Production to LNG delivery	Yes
Balcombe et al., 2021; HPDF 2-stroke	No	Yes	No	Yes	Yes	No	Production to LNG delivery	Yes
Balcombe et al., 2021; LBSI	No	Yes	No	Yes	Yes	No	Production to LNG delivery	Yes
Balcombe et al., 2021; LPDF 2-stroke	No	Yes	No	Yes	Yes	No	Production to LNG delivery	Yes
Balcombe et al., 2021; LPDF 4-stroke	No	Yes	No	Yes	Yes	No	Production to LNG delivery	Yes

Table E-9. *Harmonization of Each Study, GWP20*

Steps → Estimate ↓	Transmission Adder	Distribution Adder	LNG Segment Adder	GWP Harmonization	Preproduction Adder	Liquids-unloading Adder	Estimate Boundaries	Estimates Reported per Stage
Contreras et al., 2021; Life cycle-stage allocation	No	Yes	Yes	No	No	Yes	Production to transmission	Yes
Rai et al., 2021; ONE Future GWP100	No	No	Yes	Yes	No	No	Production to distribution	Yes
Rai et al., 2021; U.S. average GWP100	No	No	Yes	Yes	No	No	Production to distribution	Yes
Roman-White et al., 2021; China	No	Yes	No	Yes	Yes	No	Production to LNG delivery	Yes
Roman-White et al., 2021; UK	No	Yes	No	Yes	Yes	No	Production to LNG delivery	Yes
GREET, 2022	No	Yes	No	Yes	No	No	Production to LNG delivery	No
Jordaan et al., 2022	No	Yes	Yes	Yes	No	No	Production to transmission	Yes
Kelly et al., 2022; GREET 2020	No	Yes	No	Yes	No	No	Production to LNG delivery	No
Littlefield et al., 2022; MW	No	No	Yes	Yes	No	No	Production to distribution	Yes
Littlefield et al., 2022; NE	No	No	Yes	Yes	No	No	Production to distribution	Yes
Littlefield et al., 2022; Pacific	No	No	Yes	Yes	No	No	Production to distribution	Yes
Littlefield et al., 2022; Rocky	No	No	Yes	Yes	No	No	Production to distribution	Yes
Littlefield et al., 2022; SE	No	No	Yes	Yes	No	No	Production to distribution	Yes
Littlefield et al., 2022; SW	No	No	Yes	Yes	No	No	Production to distribution	Yes
Littlefield et al., 2022; U.S. average	No	No	Yes	Yes	No	No	Production to distribution	Yes

Table E-9. *Harmonization of Each Study, GWP20 (continued)*

Appendix E-5

HARMONIZATION RESULTS

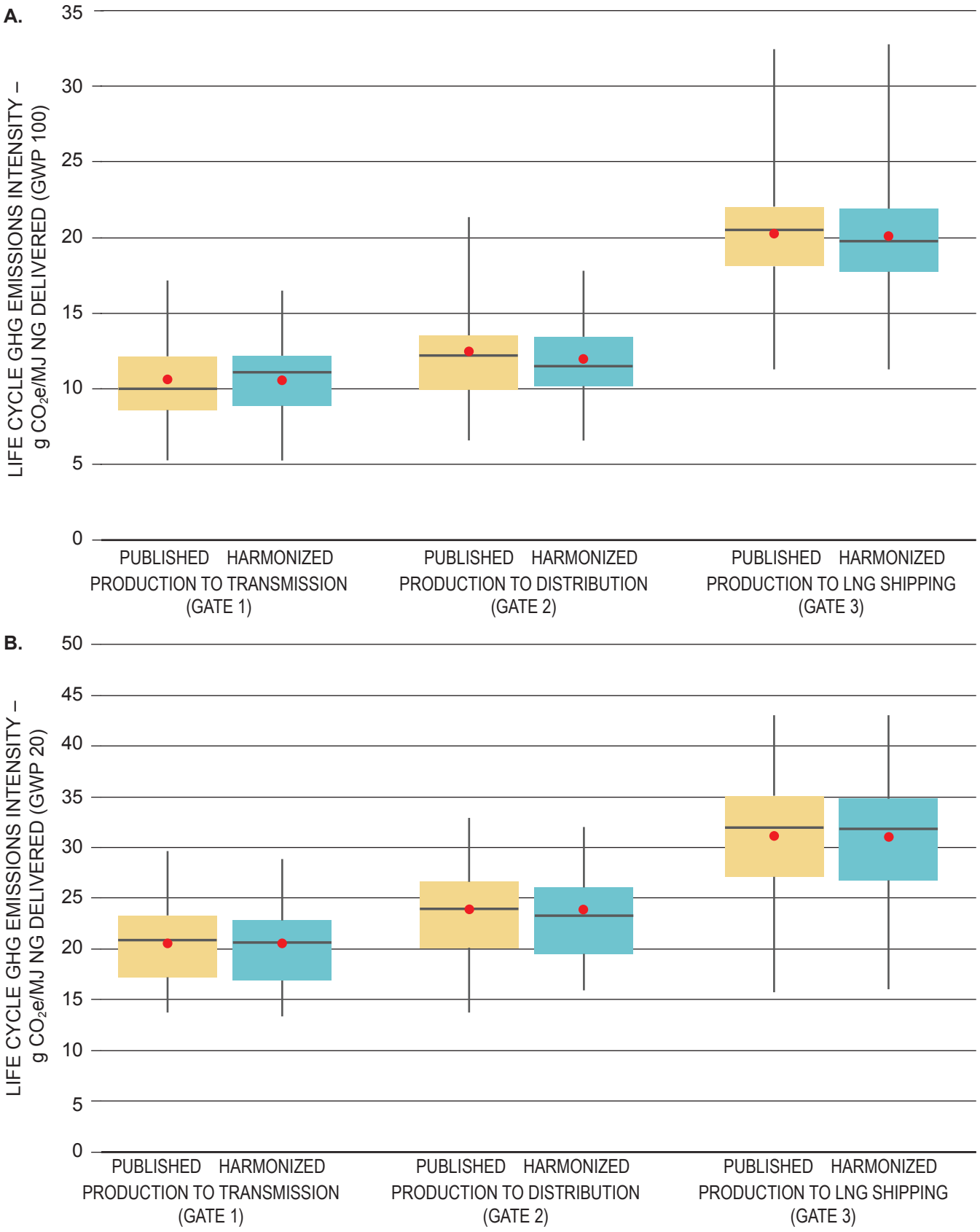
Metric (g CO_2e/MJ NG)	Published, Gate 1	Published, Gate 2	Published, Gate 3	Harmonized, Gate 1	Harmonized, Gate 2	Harmonized Gate 3 (average of all destinations)
Mean	11	12	20	10	12	20
Std. dev.	2.7	3.1	3.9	2.7	2.8	3.9
Minimum	5.3	6.6	11	5.3	6.6	11
25th percentile	8.6	9.9	18	8.9	10	17
Median	11	12	21	9.9	12	20
75th percentile	13	14	22	12	14	22
Maximum	17	21	32	16	18	33

Table E-10. *Results for Harmonized and Published Emissions Estimates, IPCC AR5 GWP100*

Metric (g CO_2e/MJ NG)	Published, Gate 1	Published, Gate 2	Published, Gate 3	Harmonized, Gate 1	Harmonized, Gate 2	Harmonized Gate 3 (average of all destinations)
Mean	21	24	31	20	24	31
Std. dev.	4.2	4.3	6.4	4.5	4.5	6.3
Minimum	14	16	16	13	16	16
25th percentile	16	20	26	16	19	26
Median	21	24	32	21	23	32
75th percentile	23	27	35	23	27	35
Maximum	30	33	43	29	32	43

Table E-11. *Harmonized and Published Results, IPCC AR5 GWP20*

Figures E-2 (a) and E-2 (b) on the next page show the published and harmonized results in the form of boxplots.



Notes: Results were characterized using (a) GWP100 for methane and (b) GWP20 for methane. Boxplots represent the ranges of the datasets—namely the minima, maxima, interquartile ranges, and central tendencies (mean as a dot and median as a line).

Figure E-2 (a) and E-2 (b). *Comparison of Published and Harmonized Life Cycle GHG Emissions Estimates for Each Study Gate*

Appendix E-6

HARMONIZATION METHANE EMISSIONS RATES

Study	Published Value	Units of Published Result	Harmonization Steps	Harmonized Value (g CH_4 emitted/g NG delivered)
Tanaka et al., 2019	1.23%	g CH_4 emitted/g NG delivered	None—already reported in harmonized form	1.23%
Roman-White et al., 2019	0.70%	g CH_4 emissions from production through pipeline transmission/g NG exiting transmission pipeline	The denominator is assumed to denote g NG delivered. Therefore, no harmonization steps applied—already reported in harmonized form.	0.70%
Roman-White et al., 2019	1.10%–1.20%	g CH_4 emissions from production through regasification/g NG exiting a regasification facility	The denominator is assumed to denote g NG delivered. Therefore, no harmonization steps applied—already reported in harmonized form.	1.10%–1.20%
Cai et al., 2017	262.9	g CH_4 emitted/MMBtu NG throughput	NG throughput is assumed to denote NG delivered. The estimate is divided by 1,055 to convert g CH_4 emitted/MMBtu NG throughput to g CH_4/MJ NG throughput. The estimate is multiplied by the higher heating value (40.58 MJ/m^3) of natural gas to convert g CH_4/MJ NG throughput to g CH_4/m^3 NG throughput. The estimate is divided by the molecular weight (alternate units) of natural gas to convert g CH_4/m^3 NG throughput to g CH_4/kg NG throughput. The estimate is divided by 1,000 to convert g CH_4/kg NG throughput to g CH_4/g NG throughput.	1.42%
	276.6	g CH_4 emitted/MMBtu NG throughput	NG throughput is assumed to denote NG delivered. The estimate is divided by 1,055 to convert g CH_4 emitted/MMBtu NG throughput to g CH_4/MJ NG throughput. The estimate is multiplied by the higher heating value (40.58 MJ/m^3) of natural gas to convert g CH_4/MJ NG throughput to g CH_4/m^3 NG throughput. The estimate is divided by the molecular weight (alternate units) of natural gas to convert g CH_4/m^3 NG throughput to g CH_4/kg NG throughput. The estimate is divided by 1,000 to convert g CH_4/kg NG throughput to g CH_4/g NG throughput.	1.50%

Table E-12. *Methods for and Results of Harmonization of Published Methane Emissions Rate for Gates Evaluated in Each Study*

Study	Published Value	Units of Published Result	Harmonization Steps	Harmonized Value (g CH_4 emitted/g NG delivered)
Roman-White et al., 2021	0.74%	g mass of methane emissions/g mass of LNG exiting liquefaction	The denominator is assumed to denote g NG delivered. Therefore, no harmonization steps applied—already reported in harmonized form	0.74%
Roman-White et al., 2021	0.90%	g mass of methane emissions/g mass of LNG exiting liquefaction	Denominator assumed to denote g NG delivered. Therefore, no harmonization steps applied—already reported in harmonized form.	0.90%
Littlefield et al., 2022	0.97%	g mass of CH_4 emissions/g mass of delivered natural gas	None—already reported in harmonized form.	0.97%
Winebrake et al., 2019, GREET, 2018	191.6	mg CH_4/MJ NG throughput	MJ NG throughput to be assumed to denote MJ NG delivered. The estimate is divided by 1,000 to convert mg CH_4/MJ NG to g CH_4/MJ NG. The estimate is multiplied by the higher heating value of natural gas (40.58 MJ/m^3) to convert g CH_4/MJ NG to g CH_4/m^3 NG. The estimate is divided by the molecular weight (alternate units) of natural gas to convert g CH_4/m^3 NG to g CH_4/kg NG. The estimate is divided by 1,000 to convert g CH_4/kg NG to g CH_4/g NG.	1.09%
	195	mg CH_4/MJ NG throughput	MJ NG throughput to be assumed to denote MJ NG delivered. The estimate is divided by 1,000 to convert mg CH_4/MJ NG to g CH_4/MJ NG. The estimate is multiplied by the higher heating value of natural gas (40.58 MJ/m^3) to convert g CH_4/MJ NG to g CH_4/m^3 NG. The estimate is divided by the molecular weight (alternate units) of natural gas to convert g CH_4/m^3 NG to g CH_4/kg NG. The estimate is divided by 1,000 to convert g CH_4/kg NG to g CH_4/g NG.	1.11%
	282.8	mg CH_4/MJ NG throughput	MJ NG throughput to be assumed to denote MJ NG delivered. The estimate is divided by 1,000 to convert mg CH_4/MJ NG to g CH_4/MJ NG. The estimate is multiplied by the higher heating value of natural gas (40.58 MJ/m^3) to convert g CH_4/MJ NG to g CH_4/m^3 NG. The estimate is divided by the molecular weight (alternate units) of natural gas to convert g CH_4/m^3 NG to g CH_4/kg NG. The estimate is divided by 1,000 to convert g CH_4/kg NG to g CH_4/g NG.	1.61%
	282.8	mg CH_4/MJ NG throughput	MJ NG throughput to be assumed to denote MJ NG delivered. The estimate is divided by 1,000 to convert mg CH_4/MJ NG to g CH_4/MJ NG. The estimate is multiplied by the higher heating value of natural gas (40.58 MJ/m^3) to convert g CH_4/MJ NG to g CH_4/m^3 NG. The estimate is divided by the molecular weight (alternate units) of natural gas to convert g CH_4/m^3 NG to g CH_4/kg NG. The estimate is divided by 1,000 to convert g CH_4/kg NG to g CH_4/g NG.	1.61%
Jordaan et al., 2022	1.3	g CO_2e/MJ NG delivered	The estimate is divided by the GWP of CH_4 used in the study to convert it to g CH_4/MJ NG. The estimate is multiplied by the higher heating value of natural gas (38.6 MJ/m^3) to convert g CH_4/MJ NG to g CH_4/m^3 NG. The estimate is divided by the molecular weight of natural gas to convert g CH_4/m^3 NG to g CH_4/kg NG. The estimate is divided by 1,000 to convert g CH_4/kg NG to g CH_4/g NG.	0.24%

Table E-12. *Methods for and Results of Harmonization of Published Methane Emissions Rate for Gates Evaluated in Each Study (continued)*

Study	Published Value	Units of Published Result	Harmonization Steps	Harmonized Value (g CH_4 emitted/g NG delivered)
	1.1	g CO_2e/MJ NG delivered	The estimate is divided by the GWP of CH_4 used in the study to convert it to g CH_4/MJ NG. The estimate is multiplied by the higher heating value of natural gas (38.6 MJ/m^3) to convert g CH_4/MJ NG to g CH_4/m^3 NG. The estimate is divided by the molecular weight of natural gas to convert g CH_4/m^3 NG to g CH_4/kg NG. The estimate is divided by 1,000 to convert g CH_4/kg NG to g CH_4/g NG.	0.19%
Meng and Dillingham, 2018	1.52%	kg CH_4 emitted/ kg natural gas delivered (same as g CH_4 emitted /g NG delivered)	None–already reported in harmonized form.	1.52%
Balcombe et al., 2018	0.80%–2.20%	g total CH_4 emitted/g CH_4 total production	The composition of natural gas is assumed to be 80% vol CH_4. This was estimated to be 75.36% mass using the molecular weights (alternate units) of natural gas and methane. The estimates are multiplied by 0.7536. To convert the estimate to a basis of g NG delivered, natural gas loss rate of 9.2% is assumed. The estimate is multiplied by 1.092.	0.66%-1.81%
Rai et al., 2021	1.06%	g mass of CH_4 emissions/g mass of natural gas delivered	None—already reported in harmonized form.	1.06%
	0.76%	g mass of CH_4 emissions/g mass of natural gas delivered	None—already reported in harmonized form.	0.76%
Balcombe et al., 2021	1.03%	g CH_4 emitted/ g NG delivered	None—already reported in harmonized form.	1.03%
Contreras et al., 2021	5.21	g CO_2e/MJ NG HHV	The estimate is divided by the GWP of CH_4 used in the study to convert it to g CH_4/MJ NG. The estimate is multiplied by the higher heating value of natural gas in the study and a conversion (1,035 Btu/scf and 1 Btu = 0.001055 MJ) to convert g CH_4/MJ NG to g CH_4/scf NG. The estimate is divided by a conversion factor (1 scf NG = 1.195 mol NG) to convert g CH_4/scf NG to g CH_4/mol NG. The estimate is divided by the molecular weight of natural gas provided (17.33 g/mol) to convert g CH_4/mol NG to g CH_4/g NG.	0.92%
	3.77	g CO_2e/MJ NG HHV	The estimate is divided by the GWP of CH_4 used in the study to convert it to g CH_4/MJ NG. The estimate is multiplied by the higher heating value of natural gas in the study and a conversion (1035 Btu/scf and 1 Btu = 0.001055 MJ) to convert g CH_4/MJ NG to g CH_4/scf NG. The estimate is divided by a conversion factor (1 scf NG = 1.195 mol NG) to convert g CH_4/scf NG to g CH_4/mol NG. The estimate is divided by the molecular weight of natural gas provided (17.33 g/mol) to convert g CH_4/mol NG to g CH_4/g NG.	0.66%

Table E-12. *Methods for and Results of Harmonization of Published Methane Emissions Rate for Gates Evaluated in Each Study (continued)*

Study	Published Value	Units of Published Result	Harmonization Steps	Harmonized Value (g CH_4 emitted/g NG delivered)
Kelly, et al., 2022; GREET, 2020	138.1	g CH_4 leakage in a stage/volumetric NG throughput in the stage (in MMBtu)	NG throughput is assumed to denote NG delivered. The estimate is divided by 1,055 to convert g CH_4 emitted/MMBtu NG throughput to g CH_4/MJ NG throughput. The estimate is multiplied by the higher heating value (40.58 MJ/m^3) of natural gas to convert g CH_4/MJ NG throughput to g CH_4/m^3 NG throughput. The estimate is divided by the molecular weight (alternate units) of natural gas to convert g CH_4/m^3 NG throughput to g CH_4/kg NG throughput. The estimate is divided by 1,000 to convert g CH_4/kg NG throughput to g CH_4/g NG throughput.	0.75%
	143.3	g CH_4 leakage in a stage/volumetric NG throughput in the stage (in MMBtu)	NG throughput is assumed to denote NG delivered. The estimate is divided by 1,055 to convert g CH_4 emitted/MMBtu NG throughput to g CH_4/MJ NG throughput. The estimate is multiplied by the higher heating value (40.58 MJ/m^3) of natural gas to convert g CH_4/MJ NG throughput to g CH_4/m^3 NG throughput. The estimate is divided by the molecular weight (alternate units) of natural gas to convert g CH_4/m^3 NG throughput to g CH_4/kg NG throughput. The estimate is divided by 1,000 to convert g CH_4/kg NG throughput to g CH_4/g NG throughput.	0.77%
	268.8	g CH_4 leakage in a stage/volumetric NG throughput in the stage (in MMBtu)	NG throughput is assumed to denote NG delivered. The estimate is divided by 1,055 to convert g CH_4 emitted/MMBtu NG throughput to g CH_4/MJ NG throughput. The estimate is multiplied by the higher heating value (40.58 MJ/m^3) of natural gas to convert g CH_4/MJ NG throughput to g CH_4/m^3 NG throughput. The estimate is divided by the molecular weight (alternate units) of natural gas to convert g CH_4/m^3 NG throughput to g CH_4/kg NG throughput. The estimate is divided by 1,000 to convert g CH_4/kg NG throughput to g CH_4/g NG throughput.	1.45%
	268.8	g CH_4 leakage in a stage/volumetric NG throughput in the stage (in MMBtu)	NG throughput is assumed to denote NG delivered. The estimate is divided by 1,055 to convert g CH_4 emitted/MMBtu NG throughput to g CH_4/MJ NG throughput. The estimate is multiplied by the higher heating value (40.58 MJ/m^3) of natural gas to convert g CH_4/MJ NG throughput to g CH_4/m^3 NG throughput. The estimate is divided by the molecular weight (alternate units) of natural gas to convert g CH_4/m^3 NG throughput to g CH_4/kg NG throughput. The estimate is divided by 1,000 to convert g CH_4/kg NG throughput to g CH_4/g NG throughput.	1.45%
GREET, 2022	148.7	g CH_4 leakage in a stage/volumetric NG throughput in the stage (in MMBtu)	NG throughput is assumed to denote NG delivered. The estimate is divided by 1,055 to convert g CH_4 emitted/MMBtu NG throughput to g CH_4/MJ NG throughput. The estimate is multiplied by the higher heating value (40.58 MJ/m^3) of natural gas to convert g CH_4/MJ NG throughput to g CH_4/m^3 NG throughput. The estimate is divided by the molecular weight (alternate units) of natural gas to convert g CH_4/m^3 NG throughput to g CH_4/kg NG throughput. The estimate is divided by 1,000 to convert g CH_4/kg NG throughput to g CH_4/g NG throughput.	0.80%

Table E-12. *Methods for and Results of Harmonization of Published Methane Emissions Rate for Gates Evaluated in Each Study (continued)*

Study	Published Value	Units of Published Result	Harmonization Steps	Harmonized Value (g CH_4 emitted/g NG delivered)
	149.7	g CH_4 leakage in a stage/volumetric NG throughput in the stage (in MMBtu)	NG throughput is assumed to denote NG delivered. The estimate is divided by 1,055 to convert g CH_4 emitted/MMBtu NG throughput to g CH_4/MJ NG throughput. The estimate is multiplied by the higher heating value (40.58 MJ/m^3) of natural gas to convert g CH_4/MJ NG throughput to g CH_4/m^3 NG throughput. The estimate is divided by the molecular weight (alternate units) of natural gas to convert g CH_4/m^3 NG throughput to g CH_4/kg NG throughput. The estimate is divided by 1,000 to convert g CH_4/kg NG throughput to g CH_4/g NG throughput.	0.81%
	206.6	g CH_4 leakage in a stage/volumetric NG throughput in the stage (in MMBtu)	NG throughput is assumed to denote NG delivered. The estimate is divided by 1,055 to convert g CH_4 emitted/MMBtu NG throughput to g CH_4/MJ NG throughput. The estimate is multiplied by the higher heating value (40.58 MJ/m^3) of natural gas to convert g CH_4/MJ NG throughput to g CH_4/m^3 NG throughput. The estimate is divided by the molecular weight (alternate units) of natural gas to convert g CH_4/m^3 NG throughput to g CH_4/kg NG throughput. The estimate is divided by 1,000 to convert g CH_4/kg NG throughput to g CH_4/g NG throughput.	1.12%
	207.4	g CH_4 leakage in a stage/volumetric NG throughput in the stage (in MMBtu)	NG throughput is assumed to denote NG delivered. The estimate is divided by 1,055 to convert g CH_4 emitted/MMBtu NG throughput to g CH_4/MJ NG throughput. The estimate is multiplied by the higher heating value (40.58 MJ/m^3) of natural gas to convert g CH_4/MJ NG throughput to g CH_4/m^3 NG throughput. The estimate is divided by the molecular weight (alternate units) of natural gas to convert g CH_4/m^3 NG throughput to g CH_4/kg NG throughput. The estimate is divided by 1,000 to convert g CH_4/kg NG throughput to g CH_4/g NG throughput.	1.12%

Table E-12. *Methods for and Results of Harmonization of Published Methane Emissions Rate for Gates Evaluated in Each Study (continued)*

I. METHANE EMISSIONS RATES USED IN SLING-GHG MODEL

Table E-12 reports harmonized methane emissions rates for the gates evaluated in each study passing systematic literature-review screens. Those methane emissions rates are interesting for informational purposes, but were not compatible with SLiNG-GHG, which requires methane emissions rates at each stage of the natural gas supply chain, production through liquefaction, to be the key model inputs (KMIs). For this purpose, stage-wise methane emissions rates were extracted from each study and the units of each estimate were adjusted to match those required in SLiNG-GHG.

Since harmonization worked with life cycle output results (as in Table E-12), published methane emissions rates were either published normalized to the functional unit (generally gas delivered to some end user) or adjusted (Table E-12) to this basis. The SLiNG-GHG model uses methane intensity as an input, but with the emissions normalized to the throughput *for each stage*. For example, the harmonization-average production methane emissions intensity was on a "per unit of gas delivered to local end user" basis, whereas the model requires production methane emissions normalized to the flow of gas produced and sold to market. To approximately rescale the published results to the "stage-level" units, the detailed harmonized results for each study passing the harmonization screening process were utilized.[6] For each stage of the supply chain, the results were rescaled using the relative ratios of "gas produced to gas delivered," "gas gathered to gas delivered," "gas processed to gas delivered," etc. This accounts for the losses and consumption of gas across the supply chain to deliver one unit to an end user: it requires more than one molecule of gas to be produced to deliver one molecule through the supply chain.

U.S. natural gas production data from EIA, along with data on venting, flaring, and fuel consumption, was used to approximate the average ratio of gross gas produced to gas exiting the gathering system. Based on reported data for 2020, of total gross production, approximately 96% of the gas will exit a gathering system (meaning approximately 4% is consumed, lost, etc.). Moving down the supply chain, based on EIA-reported data for gas delivered to processing facilities, processing plant fuel consumption, and NGL production, this study approximates another 2% of gas entering the processing facility is consumed, lost, etc. Using EIA data on pipeline gas fuel consumption paired with the flows of gas exiting processing, plus the estimated volume of gas skipping processing and flowing directly into a transmission line, this study estimates 3% of gas is consumed/lost within the transmission network. Finally, EPA recommends a default assumption of 8.10% shrinkage of gas flow for a liquefaction facility.

Using this understanding of natural gas losses/consumptions at each stage of the supply chain, this study was able to rescale published life cycle results at each stage of the supply chain to methane intensities on a per-stage basis such that the production methane KMI is input on a "grams of methane per grams of natural gas marketed production" basis, and the processing methane KMI is input on a "grams of methane per gram of natural gas exiting processing" basis, etc. While this rescaling exercise has a small impact on the resulting input value, it was a necessary exercise to align the modeling with LCA principles.

6 Note: The following studies published data in a format that allowed their harmonized results to be rescaled to produce the methane KMIs: Rai et al., 2021, Winebrake et al., 2019, Littlefield et al., 2022, GREET 2022, GREET 2021, GREET 2020, Roman-White et al., 2021, and Roman-White et al., 2019. Jordaan et al., 2022, and Crow et al., 2019, published data in such a level of aggregation it could not be appropriately parsed for use in the model as methane KMIs.

Appendix E-7

KMI DEFINITIONS, VALUE, AND SOURCES—REFERENCE CASE

Inputs	Stage: Production	Units	Values	Source
X1	CH_4 emissions rate in production	g CH_4/ g gas sales gas produced	0.46%	Average of harmonized literature
D1	Molecular weight of sales gas	lb/scf	0.052	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 (https://www.researchgate.net/publication/292838686) • API, 2021 (https://www.api.org/-/media/files/policy/esg/ghg/2021-api-ghg-compendium-110921.pdf) • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
HHV1	HHV of sales gas	Btu/scf	1,159	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
Y1	Gas consumed as fuel in combustion	MMscf gas combusted/ MMscf sales gas	6.3E-03	Roman-White et al., 2021
EF1	Combustion CO_2 emissions factor	g CO_2/MJ gas combusted	47.3	https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors
Y2	Proportion of gas flared	MMscf gas flared/MMscf sales gas	6.1E-03	GHGRP, 2022
EF2	Flaring CO_2 emissions factor	g CO_2/MJ gas flared	47.8	https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors
DE1	Destruction efficiency	%	98%	https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors

***Table E-13.** Description of KMIs and Inputs to Model*

Inputs	Stage: Production	Units	Values	Source
CH_4%	CH_4 composition (mass %) in produced gas	%	69.6%	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
F1	Energy allocation factor 1	NG/(NG+oil)	0.83	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
Inputs	**Stage: G&B**	**Units**	**Values**	**Source**
X2	CH_4 emissions rate in G&B	g CH_4/g gas leaving G&B	0.15%	Average of harmonized literature
D2	Molecular weight of gas at G&B	lb/scf	0.052	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
HHV2	HHV of gas at G&B	Btu/scf	1,159	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
TE1	Thermal efficiency of compressor driver	%	32.8%	https://dep.wv.gov/daq/Documents/January%202016%20Applications/097-000060_APPL_G35-A030B.pdf https://www.cat.com/en_US/products/new/power-systems/industrial/industrial-diesel-engines.html
ER1	Energy requirement	hp-hr/MMscf gas leaving facility	3,441	Average of harmonized literature

Table E-13. *Description of KMIs and Inputs to Model (continued)*

Inputs	Stage: G&B	Units	Values	Source
EF3	Combustion CO_2 emissions factor (for compression-combustion)	g CO_2/MJ gas combusted by driver	47.3	https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors
ER2	Electrical energy requirement	MWhr/MMscf gas leaving facility	0	-
EF4	CO_2e emissions factor for grid electricity	g CO_2e/MWhr electricity	0	-
Y3	Gas consumed as fuel in combustion	MMscf gas combusted/MMscf gas leaving facility	5.5E-03	Roman-White et al., 2021
EF5	Combustion CO_2 emissions factor	g CO_2/MJ gas combusted	47.3	https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors
CH_4%	CH_4 composition (mass %) in gas at G&B	%	69.6%	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
F1	Energy allocation factor 1	NG/(NG+oil)	0.83	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
Inputs	**Stage: Processing**	**Units**	**Values**	**Source**
X3	CH_4 emissions rate in processing	g CH_4/g gas processed	0.058%	Average of harmonized literature
D3	molecular weight of gas at processing	lb/scf	0.044	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022

Table E-13. Description of KMIs and Inputs to Model (continued)

Inputs	Stage: Processing	Units	Values	Source
HHV3	HHV at processing	Btu/scf	1,036	https://www.eia.gov/dnav/ng/ng_cons_heat_a_EPG0_VGTH_btucf_a.htm
WF(AGRU)	Weighting factor for proportion of gas going to AGRU	%	54%	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
WF(NGL)	Weighting factor for proportion of gas going to NGL recovery (cryo)	%	78%	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
AGRUCO_2i	AGRU CO_2 venting intensity (weighting factor included)	g CO_2/mcf	559	Calculated from GHGRP 2020
TE2	Thermal efficiency of compressor driver	%	32.8%	https://dep.wv.gov/daq/Documents/January%202016%20Applications/097-000060_APPL_G35-A030B.pdf https://www.cat.com/en_US/products/new/power-systems/industrial/industrial-diesel-engines.html
ER3	Energy requirement	hp-hr/MMscf gas leaving facility	1,236	Mallapragada et al., 2018
EF6	Combustion CO_2 emissions factor (for compression-combustion)	g CO_2/MJ gas combusted by driver	47.3	https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors
ER4	Electrical energy requirement	MWhr/MMscf gas leaving facility	0	-
EF7	CO_2e emissions factor for grid electricity	g CO_2e/MWhr electricity	0	-
Y4	Proportion of gas flared	MMscf gas flared/MMscf processed gas	5.0E-03	Average of harmonized literature
EF8	Flaring CO_2 emissions factor	g CO_2/MJ gas flared	49.7	https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors
DE2	Destruction efficiency	%	98%	https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors

Table E-13. *Description of KMIs and Inputs to Model (continued)*

Inputs	Stage: Processing	Units	Values	Source
Y5	Gas consumed as fuel in combustion	MMscf gas combusted/MMscf gas leaving facility	2.3E-02	Roman-White et al., 2019
EF9	Combustion CO_2 emissions factor	g CO_2/MJ gas combusted	47.3	https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors
CH_4%	CH_4 composition (mass %) in processed gas	%	91.2%	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
F2	Energy allocation factor 2	NG/(NG + NGL)	0.78	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
Inputs	**Stage: T&S**	**Units**	**Values**	**Source**
X4	CH_4 emissions rate in T&S	g CH_4/g gas leaving transmission	0.21%	Average of harmonized literature
HHV4	HHV of gas at T&S	Btu/scf	1,036	https://www.eia.gov/dnav/ng/ng_cons_heat_a_EPG0_VGTH_btucf_a.htm
D4	Molecular weight of gas at T&S	lb/scf	0.044	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
TE3	Thermal efficiency of compressor driver	%	32.8%	https://dep.wv.gov/daq/Documents/January%202016%20Applications/097-000060_APPL_G35-A030B.pdf https://www.cat.com/en_US/products/new/power-systems/industrial/industrial-diesel-engines.html
ER5	Energy requirement	hp-hr/MMscf gas leaving facility	338	Average of harmonized literature

Table E-13. *Description of KMIs and Inputs to Model (continued)*

Inputs	Stage: T&S	Units	Values	Source
EF10	Combustion CO_2 emissions factor (for compression-combustion)	g CO_2/MJ gas combusted by driver	47.3	https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors
ER6	Electrical energy requirement	MWh/MMscf gas leaving facility	0	-
EF11	CO_2e emissions factor for grid electricity	g CO_2e/MWhr electricity	0	-
Pipeline miles	Total length of transmission pipelines	miles	506	Littlefield et al., 2022
Avg Distance	Average distance between two stations	miles	55	Littlefield et al., 2022
CH_4%	CH_4 composition (mass %) in gas at T&S	%	91.2%	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
Inputs	**Stage: Distribution**	**Units**	**Values**	**Source**
X5	CH_4 emissions rate in distribution	g CH_4/g gas distributed	0.14%	Average of harmonized literature
D5	Molecular weight of gas at distribution	lb/scf	0.044	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
HHV5	HHV of gas at distribution	Btu/scf	1,036	https://www.eia.gov/dnav/ng/ng_cons_heat_a_EPG0_VGTH_btucf_a.htm
CH_4%	CH_4 composition (mass%) of gas at distribution	%	91.2%	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022

***Table E-13.** Description of KMIs and Inputs to Model (continued)*

Inputs	Stage: Liquefaction	Units	Values	Source
X6	CH_4 emissions rate in liquefaction	g CH_4/g gas liquefied	0.01%	Average of harmonized literature
D6	Molecular weight of gas at liquefaction	lb/scf	0.044	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
HHV6	HHV of gas at liquefaction	Btu/scf	1,036	https://www.eia.gov/dnav/ng/ng_cons_heat_a_EPG0_VGTH_btucf_a.htm
CO_2%	Mass % of CO_2 in gas at liquefaction (from processing)	%	3%	Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP 2022
Y6	Proportion of gas flared	MMscf gas flared/MMscf gas leaving facility	1.6E-03	GHGRP, 2022 (Cheniere SPL facility data)
DE3	Destruction efficiency	%	98%	https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors
EF12	Flaring CO_2 emissions factor	g CO_2/MJ gas flared	49.7	https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors
Y7	Gas consumed as fuel for liquefaction (shrink factor)	% (MJ gas consumed/MJ LNG produced)	8.1%	Assumptions to the Annual Energy Outlook 2023: Natural Gas Market Module (eia.gov)
EF13	Combustion CO_2 emissions factor	g CO_2/MJ gas combusted	47.3	https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors
ER7	Electrical energy requirement for liquefaction	MWhr/MJ LNG produced	0	-
EF14	CO_2e emissions factor for grid electricity	g CO_2e/MWhr electricity	0	-

Table E-13. *Description of KMIs and Inputs to Model (continued)*

Inputs	Stage: Liquefaction	Units	Values		Source
CH_4%	CH_4 composition (mass %) in gas at liquefaction	%	91.2%		Calculated from SME inputs from: • Contreras et al., 2021 • Chen et al., 2019 • Bullin and Krouskop, 2009 • API, 2021 • GREET, 2022 • EIA DPR: https://www.eia.gov/petroleum/drilling/ • GHGRP, 2022
Inputs	**Stage: Shipping**	**Units**	**Values**		**Source**
SF1	Shipping emissions factor for CO_2	tCO_2/tLNG delivered	Asia average	0.19	Roman-White et al., 2021
			Europe average	0.088	
Slip	Slip factor (gas slipped/gas combusted)	%	1.89%		
SF2	Shipping emissions factor for CH_4	tCH_4/tLNG delivered	Asia average	0.0011	
			Europe average	0.00058	

Note: All terms with MJ units in numerator or denominator (e.g., emissions factor of g CO_2/MJ gas) are on a higher heating value (HHV) basis.

Table E-13. *Description of KMIs and Inputs to Model (continued)*

Appendix E-8

COMPARISON OF MODEL RESULTS WITH MEANS FROM HARMONIZATION STUDY AND EXTERNAL MODELING TEAMS

GWP 100-yr emissions (g CO_2e/MJ NG delivered)	Production to Transmission	Production to Distribution	Production to LNG Shipping (Asia)	Production to LNG Shipping (Europe)
SLiNG-GHG model	9.9	10.6	20.2	17.6
Harmonized mean	10.5	11.9	20.0	20.0
External modeling Team 1	12.6	12.6		
External modeling Team 2		11.6	23.6	21.4
External modeling Team 3	7.3	8.2	21.0	17.8
External modeling Team 4	9.6		19.2	16.2

Table E-14. *Comparison of SLiNG-GHG Model Results with External Modeling Teams, GWP100*

GWP 20-yr emissions (g CO_2e/MJ NG delivered)	Production to Transmission	Production to Distribution	Production to LNG Shipping (Asia)	Production to LNG Shipping (Europe)
SLiNG-GHG model	19.9	22.1	33	30
External modeling Team 1	13.3	13.4		
External modeling Team 2		23.0	41.7	39.1
External modeling Team 3	12.7	15.5	31.3	27.5
External modeling Team 4	15.9		26.9	22.5

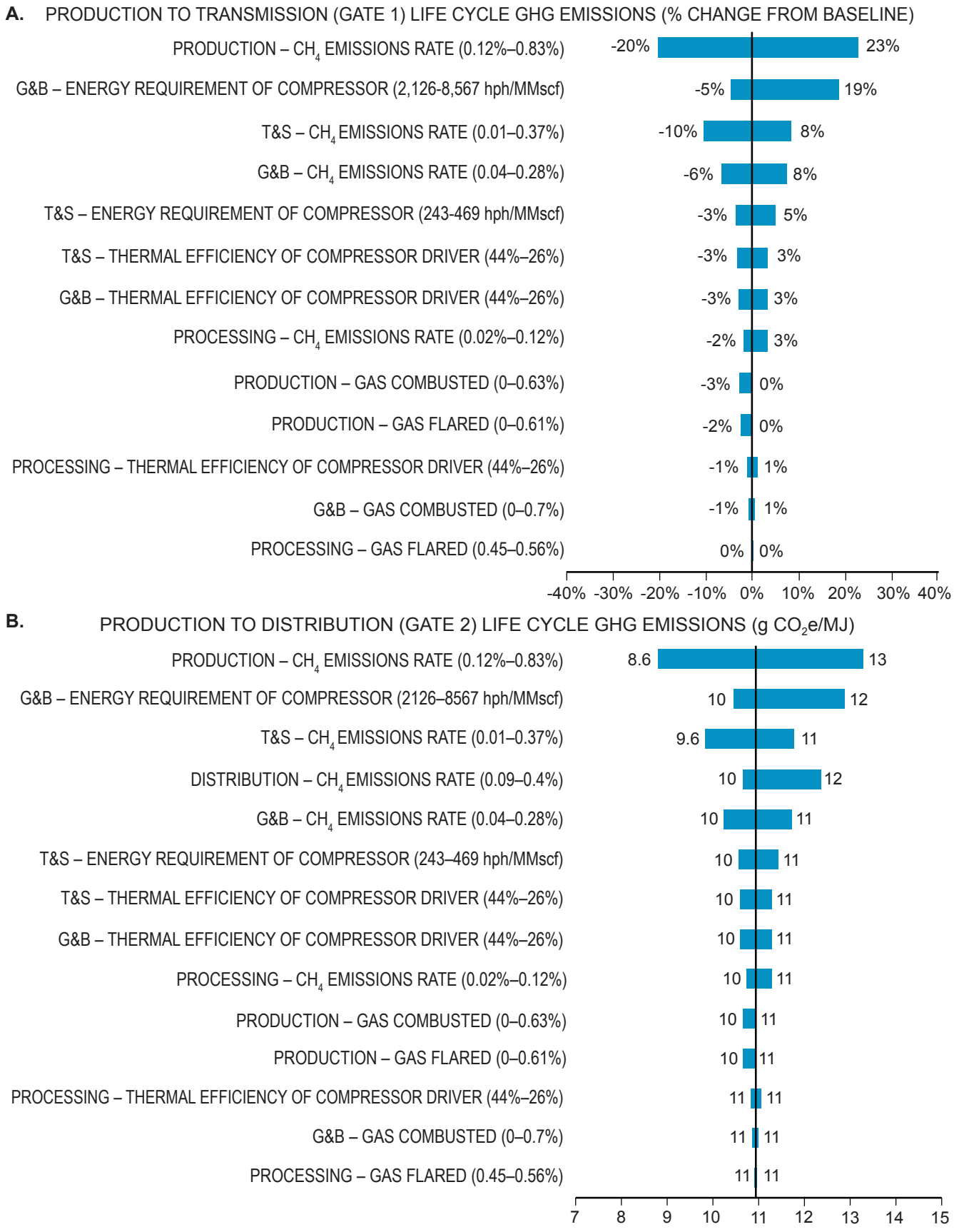
Table E-15. *Comparison of SLiNG-GHG Model Results with External Modeling Teams, GWP20*

Appendix E-9

KMI IMPACT ANALYSIS

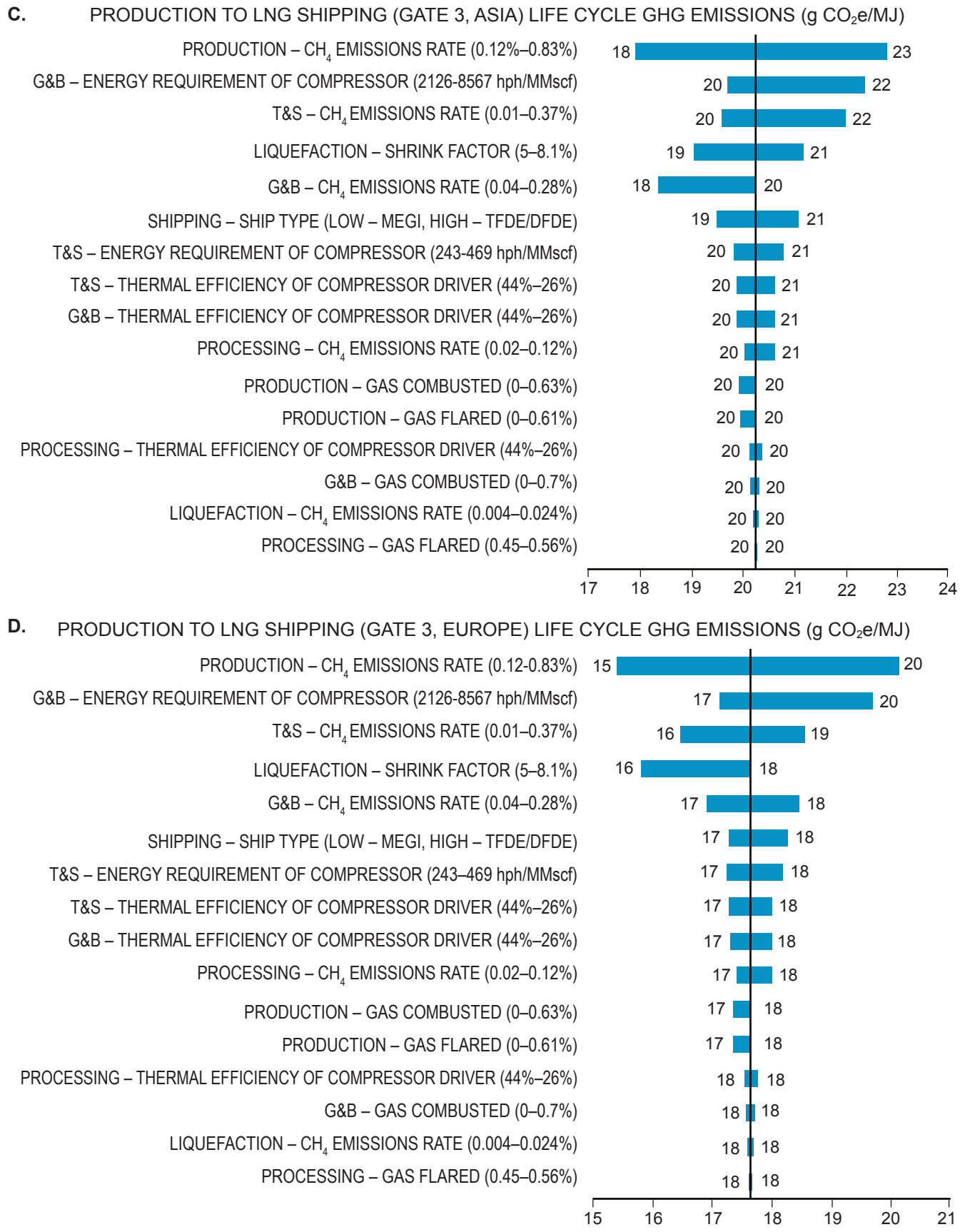
Sensitivity analysis was performed varying KMIs based on the ranges collected from the literature and SME discussions. Results were most sensitive to methane emissions rates across different stages, making these parameters the most influential of the KMIs. For each of the four cases (the three gates with two cases for Gate 3 (delivery to Asia and delivery to Europe)), production methane emissions rate and energy for compressors (gathering and boosting, G&B) were determined to be the most influential parameters. Methane emissions rates for transmission and storage ranked just after for all cases except for LNG delivery to Asia, where the emissions from shipping became more influential due to the distance. For both Gate 3 cases, results were also sensitive to liquefaction shrink and methane emissions rates. All other parameters influenced results by 4% or less when tested for the range of values presented in the literature.

Sensitivity of various KMIs for Gates, 1, 2, 3-Asia, and 3-Europe are shown on the following two pages (Figure E-3, a, b, c, and d).



Note: The range by which the parameter was varied is noted in the label in the y-axis.

Figure E-3 (a-b). *The Sensitivity of Model Results to KMIs using GWP100 Characterization Factors: (a) Gate 1 (Transmission), (b) Gate 2 (Distribution)*



Note: The range by which the parameter was varied is noted in the label in the y-axis.

Figure E-3 (c-d). *The Sensitivity of Model Results to KMIs using GWP100 Characterization Factors: (c) Gate 3 (LNG to Asia), (d) Gate 3 (LNG to Europe)*

Appendix E-10

COMPARISON OF METHANE INTENSITIES

The harmonized estimates from this project have been compared with results from a recent systematic review of measurements[7] to ensure the differences between model inputs and measurements are well documented. Balcombe et al., 2017, has an initial study pool (454 studies) much smaller than the prescreening study pool of this project (2,228 studies). The final set of studies used in Balcombe et al., 2017, (250 studies) is much larger than the postscreening study pool of this project (16 studies). The results from Balcombe et al., 2017, are not constrained to being measured after 2016, but do provide a larger pool of studies that are more specifically focused on measurement. Regarding emissions estimates, Balcombe's systematic review of measurements exhibit a wider range in comparison to the harmonized dataset of this project. The harmonized methane intensity rates fall well within the ranges outlined by Balcombe et al., 2017.

"The emissions in the study might be allocated to pipeline-quality crude oil, Y-grade NGLs, and natural gas at—one coarse level, "life cycle stage level allocation," where all emissions are allocated to all products in accordance with their relative flows at the upstream system boundary, and one fine level, "process unit level allocation," where the allocation of emissions occurs at each process unit (crude and NGL stabilizers, gas plants, etc.).[8]

7 Balcombe, P., Anderson, K., Speirs, J., Brandon, N., and Hawkes, A. 2017. *ACS Sustainable Chemistry & Engineering 5, 1, 3-20. Published October 7, 2016. https://doi.org/10.1021/acssuschemeng.6b00144.*

8 Contreras, W., Hardy, C., Tovar, K., Piwetz, A.M., Harris, C.R., Tullos, E.E., Bymaster, A., McMichael, J., and Laurenzi, I.J. 2021. "Life cycle greenhouse gas emissions of crude oil and natural gas from the Delaware Basin." *Journal of Cleaner Production*, 328(October), 129530. https://doi.org/10.1016/j.jclepro.2021.129530.

	% CH_4 emissions rate with ranges (g CH_4 emitted/g NG delivered)							
	Harmonized Median[a]	Harmonized Mean[a]	Balcombe et al., 2017[b]	Contreras et al., 2021		Published		Adjusted for Allocation
						Alvarez et al., 2018* (TD)[c]	Alvarez et al., 2018 (BU)[c]	Alvarez et al., 2018 (BU)[c]
Product and Allocation	Natural gas (allocated)	Natural gas (allocated)	Natural gas only	Natural gas (Process unit-level allocation)	Natural gas (Stage-level allocation)	Oil and gas (unallocated)	Oil and gas (unallocated)	Oil and gas (allocated)
Gate 1	0.92% (0.25%-1.96%)	0.99% (0.25%-1.96%)	-	0.92%	0.66%	-	2.06% (1.72%-2.59%)	1.87% (1.56%-2.34%)
Gate 2	1.03% (0.34%-2.35%)	1.14% (0.34%-2.35%)	0.98% (0.40%-5.31%)	-	-	1.67% (1.20%-2.13%)	2.14% (1.76%-2.74%)	1.95% (1.60%-2.50%)
Gate 3	1.17% (0.32%-2.37%)	1.19% (0.42%-2.79%)	1.17% (0.49%-5.88%)	-	-	-	-	-

Notes: a Ranges in parentheses represent minima and maxima.
b Ranges in parentheses represent minima and 95% CI upper bound as maxima.
c Ranges in parentheses represent 95% CI.

* Alvarez, R.A., Zavala-Araiza, D., Lyon, D., Allen, D., Barkley, Z., Brandt, A., Davis, K., et al. 2018. "Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain." Science 361 (6398): eaar7204. https://doi.org/10.1126/science.aar7204.

Table E-16. *Comparison Between Harmonization Results and External Studies*

Appendix E-11

KMI DEFINITIONS, VALUE, AND SOURCES—EMISSIONS REDUCTION PATHWAYS

The following table (Table E-17) details the exact KMI values modeled for each policy scenario. The data sources and assumptions used to craft these policy scenarios are documented in Chapter 1. These assumptions translate directly to how the KMI Reference case values were tuned to represent the future emissions reduction pathways. For example, the 2030 Existing Policies (EP) Scenario assumes that production methane emissions will decrease overall by 75%, and thus, the production methane KMI value decreased by 75%.

The following pathways are defined in Chapter 1.

Existing policies (EP): Methane and flaring emissions from the sector decrease to 2030 due to announced Federal policies. Consistent with EIA assumptions in the Reference case for AEO2023, there is no energy efficiency improvement or other technology advanced that reduce emissions from the sector.

Continued reductions (CR): The EP pathway to 2030, but with additional GHG emissions intensity reductions to 2050 that trend with current rates of improvement and levels of policy enablement.

Technology, Innovation, and Policy (TIP): EP pathway to 2030, but with significant policy- and technology-enabled advancements in key technologies to reduce GHG emissions in the sector (increased electrification, CCS deployment, etc.).

Inputs	Production	Units	2030 (all)	2050-EP	2050-CR	2050-TIP
X1	CH_4 emissions rate in production	g CH_4/g gas sales gas produced	0.11%	0.11%	0.10%	0.091%
D1	mol. wt. of sales gas	lb/scf	0.052	0.052	0.052	0.052
HHV1	HHV of sales gas	Btu/scf	1,159	1,159	1,159	1,159
Y1	Gas consumed as fuel in combustion	MMscf gas combusted/MMscf sales gas	6.30E-03	6.30E-03	5.36E-03	4.73E-03
EF1	Combustion CO_2 emissions factor	g CO_2/MJ gas combusted	47.3	47.3	47.3	47.3
Y2	Proportion of gas flared	MMscf gas flared/ MMscf sales gas	2.49E-03	2.31E-03	1.58E-03	1.03E-03
EF2	Flaring CO_2 emissions factor	g CO_2/MJ gas flared	47.8	47.8	47.8	47.8
DE1	Destruction efficiency	%	98%	98%	98%	98%

Table E-17. *Description of KMIs and Inputs to Model*

Inputs	Production	Units	2030 (all)	2050-EP	2050-CR	2050-TIP
CH_4%	CH_4 composition (mass %) in produced gas	%	69.6%	69.6%	69.6%	69.6%
F1	Energy allocation factor 1	NG/(NG+oil)	0.83	0.83	0.83	0.83
Inputs	**G&B**	**Units**	**2030**	**2050-EP**	**2050-CR**	**2050-TIP**
X2	CH_4 emissions rate in G&B	g CH_4/g gas leaving G&B	0.029%	0.029%	0.020%	0.014%
D2	mol. wt. of gas at G&B	lb/scf	0.052	0.052	0.052	0.052
HHV2	HHV of gas at G&B	Btu/scf	1,159	1,159	1,159	1,159
TE1	Thermal efficiency of compressor driver	%	32.8%	32.8%	32.8%	32.8%
ER1	Energy requirement	hp-hr/MMscf gas leaving facility	3,441	3,441	2,925	2581
EF3	Combustion CO_2 emissions factor (for compression-combustion)	g CO_2/MJ gas combusted by driver	47.3	47.3	47.3	47.3
ER2	Electrical energy requirement	MWhr/MMscf gas leaving facility	0	0	0	0.820
EF4	CO_2e emissions factor for grid electricity	kg CO_2e/MWhr electricity	0	0	0	32.513
Y3	Gas consumed as fuel in combustion	MMscf gas combusted/MMscf gas leaving facility	5.48E-03	5.48E-03	4.66E-03	4.11E-03
EF5	Combustion CO_2 emissions factor	g CO_2/MJ gas combusted	47.3	47.3	47.3	47.3
CH_4%	CH_4 composition (mass %) in gas at G&B	%	69.6%	69.6%	69.6%	69.6%
F1	Energy allocation factor 1	NG/(NG+oil)	0.83	0.83	0.83	0.83
Inputs	**Processing**	**Units**	**2030**	**2050-EP**	**2050-CR**	**2050-TIP**
X3	CH_4 emissions rate in processing	g CH_4/g gas processed	0.026%	0.026%	0.013%	0.005%
D3	mol. wt. of gas at processing	lb/scf	0.044	0.044	0.044	0.044
HHV3	HHV at processing	Btu/scf	1,036	1,036	1,036	1,036
WF(AGRU)	Weighting factor for proportion of gas going to AGRU	%	54%	54%	54%	54%
WF(NGL)	Weighting factor for proportion of gas going to NGL recovery (cryo)	%	78%	78%	78%	78%
AGRUCO_2i	AGRU CO_2 venting intensity (weighting factor included)	g CO_2/mcf	559	559	559	559

Table E-17. Description of KMIs and Inputs to Model (continued)

Inputs	Processing	Units	2030	2050-EP	2050-CR	2050-TIP
TE2	Thermal efficiency of compressor driver	%	32.8%	32.8%	32.8%	32.8%
ER3	Energy requirement	hp-hr/MMscf gas leaving facility	1,236	1,236	1,050.6	927
EF6	Combustion CO_2 emissions factor (for compression-combustion)	g CO_2/MJ gas combusted by driver	47.3	47.3	47.3	47.3
ER4	Electrical energy requirement	MWh/MMscf gas leaving facility	0	0	0	0.977
EF7	CO_2e emissions factor for grid electricity	kg CO_2e/MWhr electricity	0	0	0	32.513
Y4	Proportion of gas flared	MMscf gas flared/ MMscf processed gas	2.77E-03	2.77E-03	4.69E-03	1.26E-03
EF8	Flaring CO_2 emissions factor	g CO_2/MJ gas flared	49.7	49.7	49.7	49.7
DE2	Destruction efficiency	%	98%	98%	98%	98%
Y5	Gas consumed as fuel in combustion	MMscf gas combusted/MMscf gas leaving facility	2.30E-02	2.30E-02	1.95E-02	1.72E-02
EF9	Combustion CO_2 emissions factor	g CO_2/MJ gas combusted	47.3	47.3	47.3	47.3
CH_4%	CH_4 composition (mass %) in processed gas	%	91.2%	91.2%	91.2%	91.2%
F2	Energy allocation factor 2	NG/(NG + NGL)	0.78	0.78	0.78	0.78
Inputs	**T&S**	**Units**	**2030**	**2050-EP**	**2050-CR**	**2050-TIP**
X4	CH_4 emissions rate in T&S	g CH_4/g gas leaving transmission	0.081%	0.081%	0.066%	0.058%
HHV4	HHV of gas at T&S	Btu/scf	1,036	1,036	1,036	1,036
D4	mol. wt. of gas at T&S	lb/scf	0.044	0.044	0.044	0.044
TE3	Thermal efficiency of compressor driver	%	32.8%	32.8%	32.8%	32.8%
ER5	Energy requirement	hp-hr/MMscf gas leaving facility	338.463	338.463	284.3085913	253.847
EF10	Combustion CO_2 emissions factor (for compression-combustion)	g CO_2/MJ gas combusted by driver	47.3	47.3	47.3	47.3
ER6	Electrical energy requirement	MWhr/MMscf gas leaving facility	0	0	0	0.063
EF11	CO_2e emissions factor for grid electricity	kg CO_2e/MWhr electricity	0	0	0	32.513
Pipeline miles	Total length of transmission pipelines	miles	506	506	506	506
Avg Distance	Average distance between two stations	miles	55	55	55	55

***Table E-17.** Description of KMIs and Inputs to Model (continued)*

Inputs	T&S	Units	2030	2050-EP	2050-CR	2050-TIP
CH_4%	CH_4 composition (mass %) in gas at T&S	%	91.2%	91.2%	91.2%	91.2%
Inputs	**Distribution**	**Units**	**2030**	**2050-EP**	**2050-CR**	**2050-TIP**
X5	CH_4 emissions rate in distribution	g CH_4/g gas distributed	0.11%	0.11%	0.11%	0.11%
D5	mol. wt. of gas at distribution	lb/scf	0.044	0.044	0.044	0.044
HHV5	HHV of gas at distribution	Btu/scf	1,036	1,036	1,036	1,036
CH_4%	CH_4 composition (mass %) of gas at distribution	%	91.2%	91.2%	91.2%	91.2%
Inputs	**Liquefaction**	**Units**	**2030**	**2050-EP**	**2050-CR**	**2050-TIP**
X6	CH_4 emissions rate in liquefaction	g CH_4/g gas liquefied	0.003%	0.002%	0.002%	0.001%
D6	mol. wt. of gas at liquefaction	lb/scf	0.044	0.044	0.044	0.044
HHV6	HHV of gas at liquefaction	Btu/scf	1,036	1,036	1,036	1,036
CO_2%	mass % of CO_2 in gas at liquefaction (from processing)	%	3%	3%	3%	3%
Y6	Proportion of gas flared	MMscf gas flared/ MMscf gas leaving facility	1.6E-03	1.6E-03	1.6E-03	1.6E-03
DE3	Destruction efficiency	%	98%	98%	98%	98%
EF12	Flaring CO_2 emissions factor	g CO_2/MJ gas flared	49.7	49.7	49.7	49.7
Y7	Gas consumed as fuel for liquefaction (shrink factor)	% (MJ gas consumed/ MJ LNG produced)	0.081	0.081	0.07128	0.07128
EF13	Combustion CO_2 emissions factor	g CO_2/MJ gas combusted	47.3	47.3	47.3	7.1
ER7	Electrical energy requirement for liquefaction	MWhr/MJ LNG produced	0	0	0	0
EF14	CO_2e emissions factor for grid electricity	kg CO_2e/MWhr electricity	0	0	0	32.513
CH_4%	CH_4 composition (mass %) in gas at liquefaction	%	91.2%	91.2%	91.2%	91.2%

Table E-17. Description of KMIs and Inputs to Model (continued)

		Base Case	2030	Difference from Base Case	2050-EP	Difference from Base Case	2050-CR	Difference from Base Case	2050-TIP	Difference from Base Case
Gate 1	CO_2	4.9	4.7	5%	4.7	5%	4.1	17%	3.6	84%
	CH_4	0.18	0.0	72%	0.0	72%	0.0	78%	0.0	82%
	GWP100	9.9	6.1	39%	6.1	39%	5.2	48%	4.5	83%
	GWP20	19.9	8.9	55%	8.8	55%	7.4	63%	6.4	83%
Gate 2	CO_2	4.9	4.7	5%	4.7	5%	4.1	17%	3.6	84%
	CH_4	0.20	0.1	66%	0.1	66%	0.1	71%	0.1	75%
	GWP100	10.6	6.6	38%	6.6	38%	5.8	46%	5.1	79%
	GWP20	22.1	10.5	52%	10.5	52%	9.0	59%	8.1	77%
Gate 3 (Asia)	CO_2	13.8	13.5	2%	13.5	2%	12.3	11%	8.7	60%
	CH_4	0.23	0.1	66%	0.1	66%	0.1	71%	0.1	75%
	GWP100	20.2	15.7	22%	15.7	22%	14.2	30%	10.4	65%
	GWP20	33	20.1	39%	20.1	39%	17.9	46%	13.7	69%
Gate 3 (Europe)	CO_2	11.7	11.4	2%	11.4	2%	10.3	12%	6.7	69%
	CH_4	0.21	0.1	69%	0.1	69%	0.1	74%	0.0	78%
	GWP100	17.6	13.3	25%	13.3	25%	11.8	33%	8.1	72%
	GWP20	30	17.0	42%	17.0	42%	14.8	50%	10.8	75%

Table E-18. *Default KMIs for Various Pathways*

Appendix E-12

KMI DEFINITIONS, VALUE, AND SOURCES—SUPPLY CHAINS

Inputs	Production	Units	Permian-GC	App-GC	Haynesville-GC	Rockies-CA	Midcon-Midwest	App-NE
X1	CH_4 emissions rate in production	g CH_4/ g gas sales gas produced	0.08%	0.32%	0.08%	0.59%	0.33%	0.03%
D1	mol. wt. of sales gas	lb/scf	0.061	0.049	0.046	0.049	0.044	0.049
HHV1	HHV of sales gas	Btu/scf	1,180	1,100	1,020	1,133	1,190	1,020
Y1	Gas consumed as fuel in combustion	MMscf gas combusted/ MMscf sales gas	6.2E-03	3.0E-03	4.2E-03	5.2E-03	4.3E-03	7.1E-03
EF1	Combustion CO_2 emissions factor	g CO_2/MJ gas combusted	47.3	47.3	47.3	47.3	47.3	47.3
Y2	Proportion of gas flared	MMscf gas flared/MMscf sales gas	1.17E-02	9.35E-04	9.30E-05	2.02E-03	1.27E-03	2.35E-04
EF2	Flaring CO_2 emissions factor	g CO_2/MJ gas flared	47.8	47.8	47.8	47.8	47.8	47.8
DE1	Destruction efficiency	%	98%	98%	98%	98%	98%	98%
CH_4%	CH_4 composition (mass %) in produced gas	%	50.2%	74.2%	87.5%	75.6%	94.3%	74.2%
F1	Energy allocation factor 1	NG/(NG+oil)	0.44	0.86	0.99	0.85	0.85	0.99
Inputs	**G&B**	**Units**	**Permian-GC**	**App-GC**	**Haynesville-GC**	**Rockies-CA**	**Midcon-Midwest**	**App-NE**
X2	CH_4 emissions rate in G&B	g CH_4/g gas leaving G&B	0.05%	0.10%	0.03%	0.05%	0.13%	0.02%
D2	mol. wt. of gas at G&B	lb/scf	0.061	0.049	0.046	0.049	0.044	0.049
HHV2	HHV of gas at G&B	Btu/scf	1,180	1,100	1,020	1,133	1,190	1,020

***Table E-19.** Default KMIs for Different Supply Chains*

Inputs	G&B	Units	Permian-GC	App-GC	Haynesville-GC	Rockies-CA	Midcon-Midwest	App-NE
TE1	Thermal efficiency of compressor driver	%	32.8%	32.8%	32.8%	32.8%	32.8%	32.8%
ER1	Energy requirement	hp-hr/MMscf gas leaving facility	0	0	0	0	0	0
EF3	Combustion CO_2 emissions factor (for compression-combustion)	g CO_2/MJ gas combusted by driver	47.3	47.3	47.3	47.3	47.3	47.3
ER2	Electrical energy requirement	MWhr/MMscf gas leaving facility	0	0	0	0	0	0
EF4	CO_2e emissions factor for grid electricity	g CO_2e/MWhr electricity	0	0	0	0	0	0
Y3	Gas consumed as fuel in combustion	MMscf gas combusted/ MMscf gas leaving facility	2.1E-02	2.8E-02	1.1E-02	2.1E-02	1.9E-02	2.8E-02
EF5	Combustion CO_2 emissions factor	g CO_2/MJ gas combusted	47.3	47.3	47.3	47.3	47.3	47.3
CH_4%	CH_4 composition (mass %) in gas at G&B	%	50.2%	74.2%	87.5%	75.6%	94.3%	74.2%
F1	Energy allocation factor 1	NG/(NG+oil)	0.74	0.98	0.99	0.98	0.99	1.00
Inputs	**Processing**	**Units**	**Permian-GC**	**App-GC**	**Haynesville-GC**	**Rockies-CA**	**Midcon-Midwest**	**App-NE**
X3	CH_4 emissions rate in processing	g CH_4/g gas processed	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%
D3	mol. wt. of gas at processing	lb/scf	0.044	0.044	0.042	0.044	0.044	0.044
HHV3	HHV at processing	Btu/scf	951	1,027	1,009	1,036	1,000	1,027
WF (AGRU)	Weighting factor for proportion of gas going to AGRU	%						
WF (NGL)	Weighting factor for proportion of gas going to NGL recovery (cryo)	%	100%	100%	0%	0%	0%	100%

Table E-19. *Default KMIs for Different Supply Chains (continued)*

Inputs	Processing	Units	Permian-GC	App-GC	Haynesville-GC	Rockies-CA	Midcon-Midwest	App-NE
AGRU CO_2i	AGRU CO_2 venting intensity (weighting factor included)	g CO_2/mcf	623	13	446	657	171	13
TE2	Thermal efficiency of compressor driver	%	32.8%	32.8%	32.8%	32.8%	32.8%	32.8%
ER3	Energy requirement	hp-hr/MMscf gas leaving facility	1,236	1,236	0		0	1,236
EF6	Combustion CO_2 emissions factor (for compression-combustion)	g CO_2/MJ gas combusted by driver	47.3	47.3	47.3	47.3	47.3	47.3
ER4	Electrical energy requirement	MWhr/MMscf gas leaving facility						
EF7	CO_2e emissions factor for grid electricity	g CO_2e/MWhr electricity						
Y4	Proportion of gas flared	MMscf gas flared/MMscf processed gas	5.E-03	5.E-03	5.E-03	5.E-03	5.E-03	5.E-03
EF8	Flaring CO_2 emissions factor	g CO_2/MJ gas flared	49.7	49.7	49.7	49.7	49.7	49.7
DE2	Destruction efficiency	%	98%	98%	98%	98%	98%	98%
Y5	Gas consumed as fuel in combustion	MMscf gas combusted/ MMscf gas leaving facility	2.3E-02	2.3E-02	2.3E-02	2.3E-02	2.3E-02	2.3E-02
EF9	Combustion CO_2 emissions factor	g CO_2/MJ gas combusted	47.3	47.3	47.3	47.3	47.3	47.3
CH_4%	CH_4 composition (mass %) in processed gas	%	90.5%	92.9%	87.5%	91.2%	94.3%	92.9%
F2	Energy allocation factor 2	NG/(NG + NGL)	0.60	0.83	1.00	1.00	1.00	0.83
Inputs	**T&S**	**Units**	**Permian-GC**	**App-GC**	**Haynesville-GC**	**Rockies-CA**	**Midcon-Midwest**	**App-NE**
X4	CH_4 emissions rate in T&S	g CH_4/g gas leaving transmission	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%
HHV4	HHV of gas at T&S	Btu/scf	951	1,027	1,009	1,036	1,000	1,027
D4	mol. wt. of gas at T&S	lb/scf	0.044	0.044	0.042	0.044	0.044	0.044

Table E-19. *Default KMIs for Different Supply Chains (continued)*

Inputs	T&S	Units	Permian-GC	App-GC	Haynesville-GC	Rockies-CA	Midcon-Midwest	App-NE
TE3	Thermal efficiency of compressor driver	%	32.8%	32.8%	32.8%	32.8%	32.8%	32.8%
ER5	Energy requirement	hp-hr/MMscf gas leaving facility	338	338	338	338	338	338
EF10	Combustion CO_2 emissions factor (for compression-combustion)	g CO_2/MJ gas combusted by driver	47.3	47.3	47.3	47.3	47.3	47.3
ER6	Electrical energy requirement	MWhr/MMscf gas leaving facility						
EF11	CO_2e emissions factor for grid electricity	g CO_2e/MWhr electricity						
Pipeline miles	Total length of transmission pipelines	miles	493	1,149	193	1,036	919	288
Avg Distance	Average distance between two stations	miles	99	33	71	116	37	62
CH_4%	CH_4 composition (mass %) in gas at T&S	%	90.5%	92.9%	87.5%	91.2%	94.3%	92.9%
Inputs	**Distribution**	**Units**	**Permian-GC**	**App-GC**	**Haynesville-GC**	**Rockies-CA**	**Midcon-Midwest**	**App-NE**
X5	CH_4 emissions rate in distribution	g CH_4/g gas distributed	0.20%	0.21%	0.22%	0.42%	0.21%	0.21%
D5	mol. wt. of gas at distribution	lb/scf	0.044	0.044	0.042	0.044	0.044	0.044
HHV5	HHV of gas at distribution	Btu/scf	951	1,027	1,009	1,036	1,000	1,027
CH_4%	CH_4 composition (mass %) of gas at distribution	%	90.5%	92.9%	87.5%	91.2%	91.2%	92.9%
Inputs	**Liquefaction**	**Units**	**Permian-GC**	**App-GC**	**Haynesville-GC**	**Rockies-CA**	**Midcon-Midwest**	**App-NE**
X6	CH_4 emissions rate in liquefaction	g CH_4/g gas liquefied	0.01%	0.01%	0.01%			
D6	mol. wt. of gas at liquefaction	lb/scf	0.044	0.044	0.042			
HHV6	HHV of gas at liquefaction	Btu/scf	951	1,027	1,009			

Table E-19. *Default KMIs for Different Supply Chains (continued)*

Inputs	Liquefaction	Units	Permian-GC	App-GC	Haynesville-GC	Rockies-CA	Midcon-Midwest	App-NE
CO_2%	Mass % of CO_2 in gas at liquefaction (from processing)	%	0%	1%	12%			
Y6	Proportion of gas flared	MMscf gas flared/MMscf gas leaving facility	1.6E-03	1.6E-03	1.6E-03			
DE3	Destruction efficiency	%	98%	98%	98%			
EF12	Flaring CO_2 emissions factor	g CO_2/MJ gas flared	49.7	49.7	49.7			
Y7	Gas consumed as fuel for liquefaction (shrink factor)	% (MJ gas consumed/MJ LNG produced)	8.1%	8.1%	8.1%			
EF13	Combustion CO_2 emissions factor	g CO_2/MJ gas combusted	47.3	47.3	47.3			
ER7	Electrical energy requirement for liquefaction	MWhr/MJ LNG produced						
EF14	CO_2e emissions factor for grid electricity	g CO_2e/MWhr electricity						
CH_4%	CH_4 composition (mass %) in gas at liquefaction	%	90.5%	92.9%	87.5%			

Note: Unless mentioned below, the Reference case KMI input value was used.

Table E-19. *Default KMIs for Different Supply Chains (continued)*

I. ASSUMPTIONS AND KEY DATA SOURCES IN TABLE E-19

Where GHGRP inventory data were employed (which is reported at the basin level), this mapping was used to represent as closely as possible the supply chain geographies with the best available data:

- Permian to Gulf Coast = Permian Basin
- Appalachian to Gulf Coast = Appalachian Basin
- Haynesville to Gulf Coast = Average of Arkla and East Texas basins
- Rockies to West Coast = Average of Green River, Uinta, and Piceance basins
- Midcon to Midwest = Average of Arkoma, South Oklahoma, and Anadarko basins
- Appalachian to Northeast = Appalachian Eastern Overthrust Basin

Production stage methane emissions rates were derived from the EPA GHGRP inventory for 2022.[9] Total reported methane for each geography was allocated on an energy basis between gas and hydrocarbon production. Emissions were normalized to gas produced for sales to create an intensity.

9 World Resources Institute. 2020. "World Greenhouse Gas Emissions: 2020." https://www.wri.org/data/world-greenhouse-gas-emissions-2020.

Production and G&B-gas molecular weight and heating value were calculated based on reported gas composition data from published studies.[10]

EIA lease fuel data were used to represent production and gathering and boosting fuel consumption. Total lease fuel consumption was allocated between the stages based on the relative fuel splits, as reported to the EPA GHGRP 2022 inventory. The calculated relative fuel consumption splits for each geography are shown below in Table E-20. EIA lease fuel data were normalized to total marketed production. The EIA data (reported at the state level) were mapped as follows to best represent the supply chain geographies:

- **Permian to Gulf Coast:** New Mexico was selected to be the best proxy for the Permian as it is representative of the liquids production of the Permian Basin (relative to using Texas as a proxy, which also has significant dry gas production).
- **Appalachian to Gulf Coast:** Average of Pennsylvania, Ohio, and West Virginia to best represent the gas flowing from southwestern Pennsylvania and the Ohio/West Virginia region of the Appalachian
- **Haynesville to Gulf Coast:** Louisiana
- **Rockies to West Coast:** Average of Wyoming, Colorado, and Utah
- **Midcontinent to Midwest:** Average of Kansas and Oklahoma
- **Appalachia to Northeast:** Pennsylvania, to best represent the gas flowing from northeast Pennsylvania

The volume of gas flared at production was taken from EPA GHGRP reporting, using the basin mapping described above. The volume of gas flared was normalized to reported gas produced for sales.

Supply Chain	Production	G&B
Permian to GC	23%	77%
Appalachian to GC	10%	90%
Haynesville to GC	27%	73%
Rockies to WC	20%	80%
Midcon to MW	18%	82%
Appalachian to NE	20%	80%

***Table E-20.** Fuel Consumption Splits Between Production and G&B Stages for Different Supply Chains*

Gathering- and boosting-stage methane emissions rates were derived from the EPA GHGRP inventory for 2022. Total reported methane for each geography was allocated on an energy basis between gas and hydrocarbons traveling through the gathering network for the given geography. Emissions were normalized to gas exiting the gathering system to generate an intensity.

The volume of gas flared at G&B was taken from EPA GHGRP reporting, using the basin mapping described above. The volume of gas flared was normalized to reported gas exiting the gathering system.

The Reference case processing KMI values were used to estimate the energy requirements of processing and treatment as well as the methane emissions from processing; however, the model is responsive to gas composition to estimate the treatment and processing emissions (i.e., based on gas composition, the model determines what level, if any, of treatment and processing is required). Further, emissions from AGRU CO_2 venting were estimated leveraging data from the EPA GHGRP and the EIA. This is described further in the next section.

The Reference case T&S KMI values for per station modeling were used for each supply chain, however, data analysis produced by IIR was used to estimate the average pipeline distance for each pathway, as well as the average distance of pipeline between compressor stations.

10 Studies include: East Daley Analytics analysis for NPC; Contreras et al., 2021; Chen et al., 2019; Bullin and Krouskop, 2009; API, 2021 (https://www.api.org/~/media/files/policy/esg/ghg/2021-api-ghg-compendium-110921.pdf); and EIA (https://www.eia.gov/petroleum/drilling/).

Regional methane data from Littlefield et al., 2022,[11] were used to inform the distribution-stage methane KMI. See Tables SI24 and SI30 in Littlefield et al. (2022), for more information. Methane emissions were converted from a per MJ basis to a mass basis using a HHV of 1,031 Btu/scf and a density of 0.042 lb/scf.

Reference case KMI data were used for liquefaction and LNG shipping stages.

II. METHODOLOGY FOR ESTIMATING ACID GAS REMOVAL EMISSIONS INTENSITY

EPA GHGRP and EIA's Form 757 data for natural gas (NG) processing facilities were used for estimating the CO_2 emissions intensity of acid gas removal units (AGRU). It is worth noting that this effort used 2021 GHGRP data and the latest available 2017 EIA data.

GHGRP reports total CO_2 emissions from each acid gas removal unit at a NG processing facility (for facilities that meet the >25,000 mt CO_2e emissions threshold of GHGRP), which were aggregated to the facility level. Since GHGRP does not report NG throughput for processing facilities, these values were sourced from EIA data. NG throughput is used for normalizing the GHGRP-reported total CO_2 emissions and estimating the facility-level AGRU emissions intensity.

III. FACILITY MAPPING PROCEDURE

Natural gas processing facilities between the GHGRP and EIA datasets were mapped based on the facility's reported name and location data (ZIP code, county name). Out of the 250 NG processing facilities reporting to GHGRP for the 2021 data year, around 148 facilities were mapped to EIA data. The remaining 102 facilities were scrubbed from this analysis due to unavailability of throughput data. The main reasons for imperfect mapping of the GHGRP facilities to EIA data include: (1) variation in reporting year of the two datasets; (2) differences in reporting structures such as varying facility names, location details, etc., between the two datasets.

Additionally, each of the 148 facilities was mapped to a particular NG production basin based on EPA's basin shapefiles. Facilities categorized under each of the basins/regions of interest—Permian, Appalachian, Arkla, Rockies (Piceance, Green River, Uinta), and Midcontinent (Anadarko, Arkoma)—were aggregated and a throughput weighted average AGRU CO_2 emissions intensity was estimated for each basin/region, as reported in Table E-21.

Basin/Production Region	AGRU CO_2 Emissions Intensity (kg CO_2/Mcf NG)
Permian	0.62
Appalachian	0.01
Arkla	0.45
Rockies	0.66
Midcontinent	0.17

Table E-21. *Estimated AGRU CO_2 Emissions Intensity for Different NG Production Basins/Regions*

11 Littlefield, J., Rai, S., and Skone, T.J. 2022. "Life cycle GHG perspective on U.S. natural gas delivery pathways." *Environmental Science & Technology* 56 (22): 16033–42. https://doi.org/10.1021/acs.est.2c01205.

Appendix E-13

SENSITIVITY ANALYSIS (NATIONAL AND VARIOUS SUPPLY CHAIN CASES)

	National (g CO_2e/MJ HHV)			
	Production to Transmission (Gate 1)	Production to Distribution (Gate 2)	Production to Shipping (Gate 3 Asia)	Production to Shipping (Gate 3 EU)
Reference case	9.9	10.6	20.2	17.6
Lu et al.	14.6	15.3	25.6	22.9
Zhu et al.				
Lu et al., vs. Reference case (% difference)	47%	44%	27%	30%

Notes: Zhu, Y., Allen, D.T., and Ravikumar, A. 2024. "Geospatial Life Cycle Analysis of Greenhouse Gas Emissions from US Liquefied Natural Gas Supply Chains." ChemRxiv.; doi:10.26434/chemrxiv-2024-9v8dw. This content is a preprint and has not been peer-reviewed.

Lu, X., Jacob, D.J., Zhang, Y., Shen, L., Sulprizio, M.P., Maasakkers, J.D., Varon, D.J., et al. 2023. "Observation-Derived 2010-2019 Trends in Methane Emissions and Intensities from US Oil and Gas Fields Tied to Activity Metrics." *Proceedings of the National Academy of Sciences*. 120 (17). https://doi.org/10.1073/pnas.2217900120. See SI Table S4.

***Table E-22.** Sensitivity Analysis Results, National Pathway, GWP100*

	National (g CO_2e/MJ HHV)			
	Production to Transmission (Gate 1)	Production to Distribution (Gate 2)	Production to Shipping (Gate 3 Asia)	Production to Shipping (Gate 3 EU)
Reference case	19.9	22.1	33.0	29.5
Lu et al.	33.8	36.1	49.2	45.2
Zhu et al.				
Lu et al., vs. Reference case (% difference)	70%	64%	49%	53%

***Table E-23.** Sensitivity Analysis Results, National Pathway, GWP20*

	Permian to GC (g CO_2e/MJ HHV)			
	Production to Transmission	Production to Distribution	Production to Shipping (Asia)	Production to Shipping (EU)
Reference case	6.0	7.1	15.5	12.9
Lu et al.	11.0	12.1	21.3	18.4
Zhu et al.	13.7	14.8	24.4	21.5
Lu et al., vs. Reference case (% difference)	83%	70%	37%	43%
Zhu et al., vs. Reference case (% difference)	128%	109%	58%	67%

Table E-24. *Sensitivity Analysis Results, Permian to Gulf Coast Pathway, GWP100*

	Permian to GC (g CO_2e/MJ HHV)			
	Production to Transmission	Production to Distribution	Production to Shipping (Asia)	Production to Shipping (EU)
Reference case	10.8	14.1	22.5	19.0
Lu et al.	25.7	29.0	39.6	35.7
Zhu et al.	33.9	37.3	49.1	44.9
Lu et al., vs. Reference case (% difference)	138%	106%	76%	88%
Zhu et al., vs. Reference case (% difference)	214%	164%	118%	136%

Table E-25. *Sensitivity Analysis Results, Permian to Gulf Coast Pathway, GWP20*

	Appalachia to GC (g CO_2e/MJ HHV)			
	Production to Transmission	Production to Distribution	Production to Shipping (Asia)	Production to Shipping (EU)
Reference case	11.6	12.7	21.8	19.2
Lu et al.	10.4	11.5	20.5	17.9
Zhu et al.	14.2	15.3	24.8	22.1
Lu et al., vs. Reference case (% difference)	-10%	-9%	-6%	-7%

Table E-26. *Sensitivity Analysis Results, Appalachian to Gulf Coast Pathway, GWP100*

	Appalachia to GC (g CO_2e/MJ HHV)			
	Production to Transmission	Production to Distribution	Production to Shipping (Asia)	Production to Shipping (EU)
Reference case	19.6	22.9	32.3	28.9
Lu et al.	16.1	19.4	28.3	24.9
Zhu et al.	27.3	30.6	41.2	37.5
Lu et al., vs. Reference case (% difference)	-18%	-15%	-12%	-14%

Table E-27. *Sensitivity Analysis Results, Appalachian to Gulf Coast Pathway, GWP20*

	Haynesville to GC (g CO_2e/MJ HHV)			
	Production to Transmission	Production to Distribution	Production to Shipping (Asia)	Production to Shipping (EU)
Reference case	4.8	5.9	16.1	13.6
Lu et al.	10.4	11.6	22.6	19.9
Zhu et al.				
Lu et al., vs. Reference case (% difference)	118%	96%	40%	47%

Table E-28. Sensitivity Analysis Results, Haynesville to Gulf Coast Pathway, GWP100

	Haynesville to GC (g CO_2e/MJ HHV)			
	Production to Transmission	Production to Distribution	Production to Shipping (Asia)	Production to Shipping (EU)
Reference case	8.9	12.2	22.1	18.9
Lu et al.	25.8	29.2	41.7	37.9
Zhu et al.				
Lu et al., vs. Reference case (% difference)	190%	139%	89%	101%

Table E-29. Sensitivity Analysis Results, Haynesville to Gulf Coast Pathway, GWP20

	Rockies to CA (g CO_2e/MJ HHV)			
	Production to Transmission	Production to Distribution	Production to Shipping (Asia)	Production to Shipping (EU)
Reference case	9.3	11.4	N/A	N/A
Lu et al.	16.2	18.4	N/A	N/A
Zhu et al.				
Lu et al., vs. Reference case (% difference)	74%	62%	N/A	N/A

Table E-30. Sensitivity Analysis Results, Rockies to CA Pathway, GWP100

	Rockies to CA (g CO_2e/MJ HHV)			
	Production to Transmission	Production to Distribution	Production to Shipping (Asia)	Production to Shipping (EU)
Reference case	19.3	25.8		
Lu et al.	40.2	46.7		
Zhu et al.				
Lu et al., vs. Reference case (% difference)	108%	81%		

Table E-31. Sensitivity Analysis Results, Rockies to CA Pathway, GWP20

	MidCon to MW (g CO_2e/MJ HHV)			
	Production to Transmission	Production to Distribution	Production to Shipping (Asia)	Production to Shipping (EU)
Reference case	9.7	10.8		
Lu et al.	24.0	25.2		
Zhu et al.				
Lu et al., vs. Reference case (% difference)	148%	133%		

Table E-32. *Sensitivity Analysis Results, MidCon to Midwest Pathway, GWP100*

	MidCon to MW (g CO_2e/MJ HHV)			
	Production to Transmission	Production to Distribution	Production to Shipping (Asia)	Production to Shipping (EU)
Reference case	17.2	20.5		
Lu et al.	60.2	63.6		
Zhu et al.				
Lu et al., vs. Reference case (% difference)	250%	210%		

Table E-33. *Sensitivity Analysis Results, MidCon to Midwest Pathway, GWP20*

	App to NE (g CO_2e/MJ HHV)			
	Production to Transmission	Production to Distribution	Production to Shipping (Asia)	Production to Shipping (EU)
Reference case	5.5	6.6		
Lu et al.	6.6	7.7		
Zhu et al.	10.3	11.4		
Lu et al., vs. Reference case (% difference)	20%	17%		

Table E-34. *Sensitivity Analysis Results, Appalachia to Northeast Pathway, GWP100*

	App to NE (g CO_2e/MJ HHV)			
	Production to Transmission	Production to Distribution	Production to Shipping (Asia)	Production to Shipping (EU)
Reference case	9.0	12.3		
Lu et al.	12.3	15.6		
Zhu et al.	23.2	26.5		
Lu et al., vs. Reference case (% difference)	36%	27%		

Table E-35. *Sensitivity Analysis Results, Appalachia to Northeast Pathway, GWP20*

Appendix E-14

ADDITIONAL SPECIAL CONSIDERATIONS IN LCAs

I. IMPACT ASSESSMENT METRICS

In LCA Midpoint indicators, or characterization factors, aggregate emissions relate to specific environmental impacts, such as climate change, with 100-year GWP being the most commonly utilized metric. By contrast, endpoint indicators weigh and aggregate a variety of midpoint indicators to estimate the environmental impact of a product on: (1) human health, (2) biodiversity, and (3) resource depletion. Weighting of midpoint indicators as diverse as climate change (global warming), terrestrial acidification, and freshwater eutrophication to estimate the effect of a product on human health remains controversial, but there are methods commonly utilized by LCA practitioners for this purpose. Among these, the ReCiPe model[12] may be the most widely utilized, integrating 18 midpoint indicators to yield the three aforementioned endpoint indicators.

Aside from scientific questions about the robustness of the aggregation of midpoint indicators, there are practical reasons why most LCAs do not employ endpoint indicators. For every additional environmental metric, the amount of data required to do the LCA may increase geometrically, as new categories of emissions and other environmental impacts must be collected.

II. RENEWABLE ENERGY CERTIFICATES (ACCOUNTING FOR USE IN THE CONTEXT OF LCA)

Renewable energy certificates (RECs) can be purchased from the market as a commodity to represent ownership of one megawatt-hour (MWhr) of renewably generated electricity. RECs on their own are an accounting mechanism, and do not necessarily represent a direct contractual relationship between the power generator and the purchaser of the credit. RECs can be traded on the market and eventually retired to offset carbon emissions in a purchaser's GHG emissions inventory.

RECs only certify the renewable nature of the energy sources that are used to produce electricity. However, RECs do not necessarily provide a life cycle emissions factor for electricity. From a life cycle perspective, it is important to account for the emissions associated with generating electricity. While there are tools available to support these calculations (such as the National Energy Technology Laboratory (NETL) grid mix explorer tool), the use of these tools requires knowledge about power generation and embodied carbon, which may not always be available. There are also challenges regarding the accounting systems for tracking RECs.[13] A robust, global clearinghouse does not exist for ensuring RECs are appropriately tracked and retired to avoid any double counting.

Furthermore, different regulations and carbon trading platforms may have different requirements on the use of RECs in the life cycle carbon emissions calculations. For example, the California Low Carbon Fuel Standard does not allow the use of RECs to reduce the emissions from electricity used in the transportation fuel production process, unless it's used for hydrogen production.[14]

12 RIVM. 2011. "LCIA: The ReCiPe Model." https://www.rivm.nl/en/life-cycle-assessment-lca/recipe.

13 Naik, Gautam. "Problematic Corporate Purchases of Clean Energy Credits Threaten Net Zero Goals." SandP Global, May 5, 2021. https://www.spglobal.com/esg/insights/problematic-corporate-purchases-of-clean-energy-credits-threaten-net-zero-goals.

14 California Air Resources Board. 2020. "Unofficial Electronic Version of the Low Carbon Fuel Standard Regulation." https://ww2.arb.ca.gov/sites/default/files/2020-07/2020_lcfs_fro_oal-approved_unofficial_06302020.pdf.

Appendix E-15

ADDITIONS TO RECOMMENDATION 5 IN CHAPTER 4 ON FRAMEWORKS AND TOOLS TO ENHANCE LCAs

RECOMMENDATION FOR DEVELOPMENT OF A FRAMEWORK TO INTEGRATE METHANE EMISSIONS MEASUREMENTS INTO LCAS

The NPC recommends that the Department of Energy (DOE) sponsor the creation of a multistakeholder Measurements and Life Cycle Assessment Advisory Group to meet periodically and provide a report with guidelines and periodic updates on integrating methane emissions measurement data from multiple technologies such as satellites, aerial surveys, and continuous monitoring systems into conventional LCA frameworks. These guidelines should be incorporated into common DOE LCA models such as the National Energy Technology Laboratory (NETL) LCA model or Argonne National Lab's GREET model.

Measurement-informed LCAs are critical to compare relative emissions intensities of U.S. and global natural gas supply chains. However, emissions estimates produced from measurement campaigns do not align well with the input parameters of conventional LCA models. Guidelines are needed for both measurement campaigns to report data in formats that would enable the development of effective and comprehensive measurement-informed life cycle emissions inventory, as well as LCA practitioners to interpret measurement data in the context of life cycle model inputs. These guidelines can further enable the intercomparison of life cycle emissions across global natural gas supply chains by providing a common framework to incorporate measurement data (e.g., satellite) from different global gas-producing regions with a shared LCA framework.

- Group Members: The multistakeholder group participants could include DOE, EPA, LCA practitioners from National Laboratories, academic institutions, natural gas operators, measurement experts from industry, universities, NGOs, and other stakeholders as determined by the Report Development Leadership.

- Report Development Leadership: The National Academy of Sciences (NAS) has a history of convening relevant stakeholders and developing state-of-the-science reports on the topic of methane emissions and GHG emissions measurements. In addition, academic institutions, nonprofit organizations, and industry trade groups have played convening roles that bring together diverse stakeholders to develop guidance documents. The NAS, or other agreed-upon group, should establish a public and transparent process for soliciting membership, scheduling meetings, developing reports, instituting a process to incorporate stakeholder feedback, and making the final report publicly available.

- Report Content: The report will include, but not be limited to, methodological guidelines to report methane emissions intensities at appropriate spatial scales for integration into LCA, emissions allocation methods for top-down measurement data, approaches to incorporate measurement data from different technologies in life cycle emissions inventories, and guidelines on treatment of emissions intermittency. Sections of the report will be updated annually as required, based on advances in new technologies, availability of new datasets, and improvements in LCA method.

ACRONYMS AND ABBREVIATIONS

Acronym	Meaning
45Q	Carbon-dioxide Capture Credit
45V	Clean Hydrogen Tax Credit
AEO2023	Annual Energy Outlook 2023
AMEL	Alternative Means of Emissions Limitations
ANCSA	Alaska Native Claims Settlement Act
API	American Petroleum Institute
APS	Announced Policies Scenario
AR5	IPCC Assessment Report 5
ARPA-E	Advanced Research Projects Agency-Energy
AVO	Audio, Visual, and Olfactory
Bcf/d	Billion cubic feet per day
BLM	Bureau of Land Management
Boe/d	Barrels of oil equivalent per day
BOEM	Bureau of Ocean Energy Management
BSEE	Bureau of Safety and Environmental Enforcement
Btu	British Thermal Unit
CAA	Clean Air Act
CAFE	Corporate Average Fuel Economy
CBP	Community Benefits Plan
CC	Combined Cycle
CCAC	Climate & Clean Air Coalition
CCS	Carbon Capture and Storage
CEJST	Climate and Economic Justice Screening Tool
CEQ	Council on Environmental Quality
CES	Clean Energy Standard
Cf/bbl	Cubic feet per barrel
CFP	Carbon Footprint
CH_4	Methane
CI	Carbon Intensity
CLGC	Closed Loop Gas Capture
CMS	Continuous Monitoring System
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
COP	Conference of the Parties
CR	Continued Reduction Pathway
cu ft/bbl	Cubic feet per barrel
DAC	Direct Air Capture
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DOT	U.S. Department of Transportation
EIA	U.S. Energy Information Administration
EJ	Environmental Justice
EO	Executive Order
EP	Existing Policies Pathway

Acronym	Meaning
EPA	U.S. Environmental Protection Agency
ETS	Emissions Trading System
EU	European Union
EVIC	Enterprise Value Including Cash
FERC	Federal Electric Regulatory Commission
FY	Fiscal Year
gCO_2e	grams of carbon dioxide equivalent
GHG	Greenhouse Gas
GHGI	Greenhouse Gas Inventory
GHGRP	Greenhouse Gas Reporting Program
GREET	Greenhouse Gases, Regulated Emissions and Energy Use in Technologies LCA Model
GWP	Global Warming Potential
GWP100	100-year Global Warming Potential
GWP20	20-year Global Warming Potential
H_2S	Hydrogen Sulfide
HAPS	High Altitude Platform Systems
HHV	Higher Heating Value
HI-SUP	High Oil and Gas Supply
IEA	International Energy Agency (IEA)
IIJA	Infrastructure Investment and Jobs Act
IMEO	International Methane Emissions Observatory
IMO	International Maritime Organization
IPCC	Intergovernmental Panel on Climate Change
IRA	Inflation Reduction Act
ISO	International Organization for Standardization
KMI	Key Model Input
LCA	Life Cycle Assessment
LCFS	Low Carbon Fuel Standard
LCO	Less Capitalized Operator
LDAR	Leak Detection and Repair
LDC	Local Distribution Company
LEG	Louisiana Energy Gateway
LEL	Lower Explosive Level
LHV	Lower Heating Values
LiDAR	Light Detection and Ranging
LNG	Liquefied Natural Gas
LO-LO	Low Macro and Low Zero Carbon Technology
LO-SUP	Low Oil and Gas Supply
LWCF	Land and Water Conservation Fund
MAC	Marginal Abatement Cost
MEMS	Micro-Electrical-Mechanical Systems
MERP	Methane Emissions Reduction Program
METEC	Methane Emissions Technology Evaluation Center
MJ	Mega-Joule
MMBtu	Million British Thermal Units
MMRV	Measurement, Monitoring, Reporting, and Verification
MMscf	Million Standard Cubic Feet
MMscf/d	Million Standard Cubic Feet per Day
MT	Metric Tons
MMT	Million Metric Tons
$MMTCO_2e$	Million Metric Tons of Carbon Dioxide Equivalent
NAESB	North American Energy Standards Board
NASEM	National Academies of Sciences, Engineering, and Medicine
NDC	Nationally Determined Contributions
NDIC	North Dakota Industrial Commission
NEMS	National Energy Modeling System
NEPA	National Environmental Policy Act

Acronym	Meaning
NETL	National Energy Technology Laboratory
NG	Natural Gas
NGL	Natural Gas Liquids
NGO	Nongovernmental Organizations
NGSC	Natural Gas Supply Chain
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrogen Oxides
NPC	National Petroleum Council
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standard
NZ2050	Net Zero by 2050 Scenario
OCS	Outer Continental Shelf
OGCI	Oil and Gas Climate Initiative
OGI	Optical Gas Imaging
OGMP	Oil and Gas Methane Partnership
P&A	Plug and Abandon
PHMSA	Pipeline Hazardous Materials Safety Administration
PM	Particulate Matter
PTTC	Petroleum Technology Transfer Council
Q1, Q2, Q3, Q4	First Quarter, Second Quarter, Third Quarter, Fourth Quarter
RDD&D	Research Development, Demonstration and Deployment
ROW	Right-of-Way
RPS	Renewable Portfolio Standards
SC	Simple-cycle
SCADA	Supervisory Control and Data Acquisition
SCI	Societal Considerations and Impacts
SLiNG-GHG	Streamlined Life Cycle Assessment Natural Gas Model
SO_2	Sulfur Dioxide
Tcf	Trillion Cubic Feet
TIP	Technology, Innovation, and Policy Pathway
UAV	Unmanned Aerial Vehicle
UNEP	United Nations Environmental Programme
UNFCCC	United Nations Framework Convention on Climate Change
VOC	Volatile Organic Compound
ZCTC	Zero-Carbon Technology Cost

DESCRIPTION OF ADDITIONAL MATERIALS

In addition to approving this report, the members of the National Petroleum Council (NPC) approved making materials used in the study process available through the NPC website: chartingthecourse.npc.org.

STREAMLINED LIFE CYCLE ASSESSMENT OF NATURAL GAS – GREENHOUSE GAS MODEL (SLiNG-GHG)

There is a growing interest in understanding the life cycle greenhouse gas (GHG) emissions associated with U.S. natural gas production and exports. Life Cycle Assessments (LCA) can be specific to GHGs (carbon footprinting) to inform emissions reduction opportunities along the natural gas supply chain and support the understanding of emissions intensities of supply chains. Growing interest in life cycle GHG emissions from natural gas systems is hindered by modeling complexity and other factors, including expertise.

To demonstrate an approach that would enable wider use of LCA tools in public policy and corporate strategies across the natural gas supply chain, the NPC supported research by McGill University (Montreal, Quebec, Canada) and the National Renewable Energy Laboratory (NREL, Golden, Colorado) and cooperated in the development of an open-source, user-defined, simplified, and streamlined natural gas well-to-gate LCA model, SLiNG-GHG, that can generate reasonably representative, screening-level GHG emissions estimates. The SLiNG-GHG model was developed to focus on the key GHG emissions sources from the natural gas supply chain, as informed from past published literature as well as subject matter experts involved in the study. By focusing on the key sources of emissions, SLiNG-GHG is easier for non-LCA experts to use.

NOTE: The SLiNG-GHG model was developed under an agreement between the NPC and McGill University and the NREL to support the *Charting the Course* report. The model was used to support analysis for the study and to facilitate related modeling but is not itself approved by the NPC as part of its report. The design and function of and access to the SLiNG-GHG model, the host website, and any changes to the model are the work of McGill University, which is solely responsible for its function and content.

The NPC has approved providing access to the SLiNG-GHG model and user guide through McGill University. For information on how the study analysis used the SLiNG-GHG model, please refer to Chapter 4 in the *Charting the Course* report.

TOPIC PAPERS

The topic papers are working documents that were part of the analyses that led to development of results presented in the report's Executive Summary and chapters.

These topic papers represent the views and conclusions of the authors. The NPC was not asked to endorse or approve the statements and conclusions contained in these documents, but to approve making these materials available on the NPC report website (chartingthe-course.npc.org) as part of the study process.

The titles and authors of the topic papers are as follows:

1. *User Manual – Streamlined Life Cycle Assessment of Natural Gas – Greenhouse Gases (SLiNG-GHG) Model.* Sai Jayaraman, McGill University; Adithya Srikanth, McGill University; Sarah Jordaan, McGill University; Garvin Heath, National Renewable Energy Laboratory.
2. *Global Warming Potential (GWP) Description.* Andrew Pomerantz, SLB Corporation; Robert Kleinberg, Columbia University; Robert Stout, EarthX; Fiji George, Cheniere Energy, Inc.; Jon Goldstein, Environmental Defense Fund.
3. *The Case for Resiliency, Synchronization and Enduring Policies Concerning Methane in the Energy Transition.* Jesse D. Frederick, PE and VP of WZI Inc.
4. *Orphan/Abandoned/Undocumented Wells.* Selina Roman-White, Cheniere Energy, Inc.; Sarah Izzat, Occidental Petroleum Corporation; Ian Laurenzi, Exxon Mobil Corporation; Chuck Brecher, Baker Hughes Company.
5. *Methane Hydrates in Alaska.* Christine Resler, ASRC Energy Services Alaska LLC; Amanda S. Henry, ASRC Energy Services Alaska LLC; Ray Boswell, National Energy Technology Laboratory; Okinaka Norihiro, Japan Organization for Metals and Energy Security; Nakatsuka Yoshihiro, Japan Organization for Metals and Energy Security.
6. *Overview of Certified Natural Gas Registries.* Jonathan Booe, North American Energy Standards Board; Clare Callahan, Deloitte Consulting; Jonah Saacks, Deloitte Consulting.